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CORE – Coordinated operation of integrated energy systems

WP1 - Renewable based Energy System with P2H and P2G

Sorknæs, Peter; Korberg, Andrei David; Johannsen, Rasmus Magni; Petersen, Uni Reinert; Mathiesen, Brian Vad

Publication date:
2020

[Link to publication from Aalborg University](#)

Citation for published version (APA):

Sorknæs, P., Korberg, A. D., Johannsen, R. M., Petersen, U. R., & Mathiesen, B. V. (2020). CORE – Coordinated operation of integrated energy systems: WP1 - Renewable based Energy System with P2H and P2G.

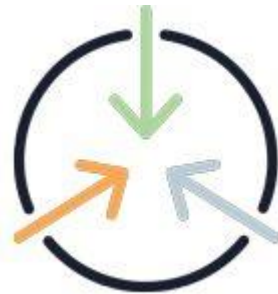
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CORE – Coordinated operation of integrated energy systems

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Authors: Peter Sorknæs, Andrei David Korberg, Rasmus Magni Johannsen, Uni Reinert Petersen, Brian Vad Mathiesen

Date: 30. 11. 2020



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Abbreviations

CEEP: Critical excess electricity production

CHP: Combined heat and power

COP: Coefficient of performance

DH: District heating

GCA: Global climate action

HP: Heat pump

IDA: Danish Society of Engineers

IRR: Internal rate of return

OM: operation and maintenance

P2H: Power-to-heat

P2G: Power-to-gas

PV: Photovoltaic

RES: Renewable energy source

ST: Sustainable transition

TYNDP: Ten Year Network Development Plan

VRES: Variable renewable energy source

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1 Summary

This report is the result of the work in Work Package 1 of the EUDP funded project Coordinated Operation of Integrated Energy Systems (CORE).

The purpose of the work presented in this report is to utilise existing energy system scenarios from different Danish actors to analyse how different technologies could affect different types of future energy systems where renewable technologies supply all energy demands. A special focus is on power-to-heat (P2H) and power-to-gas (P2G) technologies, though the scope is not limited to these technologies. The work includes scenarios for both the long-term 2050 energy system where the Danish energy system is based on 100% renewable energy, but also a medium-term perspective for 2035. The medium-term is included as different technologies might have different roles in 100% renewable energy systems than in energy systems with a lower share of renewable energy. In turn, this is useable for policy considerations in regards to which technologies should be implemented early and which should wait until the share of renewable energy in the energy system is higher, and which technologies are only relevant in the transition towards 100% renewable energy.

The scenarios used are from the Danish Society of Engineers' (IDA) report "IDA's Energy Vision 2050" from 2015 [1] and the Danish transmission system operator Energinet's "System Perspective 2035" from 2018 [2]. The energy system scenarios in both of these reports include all energy sectors, though they detail parts of them differently, and both use the years 2035 and 2050 as modelling years, meaning that they have the same years for a medium- and long-term outlook. A reference model for the Danish energy system in 2020 is also made using projections from before 2020, to be used as a representative model for the current Danish energy system. An overview of the scenarios used is shown in Figure 1.

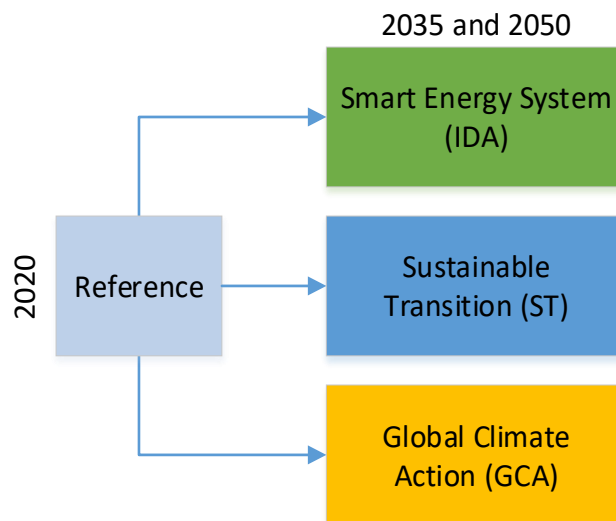


Figure 1 – Scenarios used in the analyses

The scenarios are used in a modelling testbed, where the scenarios are set up and adjusted to make them comparable without changing the main aspects of each scenario. More specifically, all scenarios are mod-

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elled in the same energy system modelling tool, EnergyPLAN, and all costs are updated so that they are using the same updated technology data. Using the modelling testbed, four different focus areas are analysed:

- Operational analyses of the scenarios under different market price projections. Here the focus is on the operation of technologies based on the original technical setup of the scenarios.
- Electrification of the energy system, where the focus is on the electricity system. More specifically the following has been investigated: Industry electrification, Electricity demand flexibility, and Grid-scale electricity storage.
- Heat sector, where the focus is on the individual and district heating systems. More specifically the following has been investigated: Heat savings, Individual heating solution incl. heat storages, District heating production technologies (combined heat and power units and heat pumps), and District heating storages.
- Renewable fuels in the Danish energy system, where the focus is on the role and production of different renewable fuels. More specifically the following has been investigated: Biogas, Dry biomass, Electrolyser flexibility, and Electrification and electrofuels in transport.

The following summarises the main findings from each analysed focus area.

Operational analyses:

Going towards increasing levels of renewable energy in the energy system results in decreasing yearly operation of the power and combined heat and power (CHP) plants, even in scenarios with a significant decrease in the CHP and power plant capacity. Even though the yearly operation of these plants is reduced, there are still hours where the full capacity of these units is needed, indicating that the value of these plants shifts from being the energy produced to instead be the capacity offered. As such, markets must adapt to this change in value, as a given capacity of CHP or power plant will require more income per amount of electric energy produced to cover the long-term marginal costs. Another option is to consider this as part of the support system or infrastructure needed in integrated renewable energy systems.

Transmission line capacity is found to be utilised more for the needs of the Danish energy system in 2050 compared to 2035, though the full capacity of the transmission lines is only utilised for needs in the Danish energy system in a small part of the year, especially in scenarios where the transmission line capacity is expanded.

Electrification:

Systems with low internal dispatchable power production capacity are more sensitive to external markets and external electricity prices. This is relevant in the discussions on future energy system electrification, as it is inherently connected to both internal electricity production capacity and transmission capacity, and as also has been the case historically it is expected that energy prices will fluctuate from year to year. Also, long-term predictions of energy prices have shown to be very uncertain, and as such, having internal dispatchable power production capacity reduces the effect of these uncertainties.

For the industry sector, direct industry electrification should be favoured over a fuel shift to hydrogen-based processes due to lower costs and higher system efficiency. Hydrogen should instead be prioritised for specific

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processes without alternative solutions, or where the value of local utilisation of bi-products is significant enough to make up for the extra costs for the energy system.

Electricity demand flexibility can contribute to increased integration of variable renewable electricity, though the effects of this are limited to the available capacity and electricity demand flexibility only allows the demands to be moved within a relatively short period of max. a week, and flexibility for longer periods is also needed. Uncertainties remain in relation to the actual achievable flexibility amount and the related investment costs needed; as such, there is a continued need for research on quantifying and realising this potential.

Li-ion batteries for grid-scale storage are infeasible based on hourly balancing, and should not be implemented with such a primary role. Li-ion batteries may, however, be useful for other purposes such as back-up capacity or for short-term balancing and frequency regulation, though other already utilised technologies could provide these services. From preliminary technical and economic assumptions, high-temperature rock bed storage seems feasible as a cheaper alternative to li-ion batteries for electricity storage. However, this needs to be verified in future models as improved technical data becomes available.

Heating:

Heat savings are found to be important both for reducing the total annual costs of the energy system but also to reduce the biomass consumption of the energy system. In relation to energy system costs the optimal level of heat savings was found to be approximately 32% compared with the average consumption per m² in 2010. This was analysed in the IDA scenario for 2050. Though the biomass consumption should also be considered in this respect, as to keep biomass consumption within sustainable levels. In the IDA scenario for 2050, going from 32% to 42% heat savings increases the total annual cost of the system by less than 0.2% of total annual costs but reduces the biomass consumption by about 3.5% of the total biomass consumption.

In relation to individual heating supply, electric-driven heat pumps should be used as much as possible for individual heating to keep the biomass consumption and the total annual cost of the energy system low. Individual solar thermal as a supplement heating supply can help reduce the use of biomass of the energy system, though its potential is limited due to its production mainly being in the summer period.

Individual heat storage technologies in connection with heat pumps and solar thermal can reduce the biomass consumption of the energy system, but only up to a certain point, depending on the amount of other flexible electricity demands in the scenario, though research has shown that from an energy system cost perspective only low-cost individual storage options should be considered.

District heating is found to be an important infrastructure in all the investigated energy system scenarios, as it allows collection and utilisation of otherwise discarded heat by distributing it to end-users. In the future district heating is expected to be mainly supplied by both large-scale heat pumps, excess heat from electro-fuel production, geothermal, and CHP plants. The large-scale heat pumps and CHP plants are found to provide flexibility to the energy system, especially when heat storages are utilised.

For CHP and power plants high electric efficiency of the CCGT is found to provide the energy system with the lowest costs and lowest biomass consumption. Having internal flexible CHP or power plant capacity in the energy system makes it possible to reduce the total annual costs of the energy system, but as shown in other analyses also stabilises the total annual costs in relation to changing international electricity market prices.

Summary

The use of large-scale CHP units instead of pure power plants is not a necessity for keeping the biomass consumption of the energy system at low levels, as long as the pure power plants are highly efficient and sufficient amounts of other low-cost heat sources for district heating, such as HPs, are available in the system.

Renewable fuels:

Biomass conversion technologies and electrofuels will have a crucial role in future energy systems, but it is also important that the biomass consumption is kept within the sustainable boundaries. Generally, producing any type of liquid or gaseous renewable fuels is more expensive and less efficient than electrification, so priority should always be given to electrification where possible. Electrofuels can supply the demands in the parts of the transport sector where direct electrification cannot.

Electrolysers used as part of producing electrofuels can provide a considerable potential for flexible for the electricity system, provided sufficient hydrogen storage exists. In this the optimal balance for the Danish energy system is found to be somewhere between 2.5 and 4 days of hydrogen storage combined with an electrolyser capacity of about 1.6-1.7 times the minimum needed capacity. The actual sizing depends on the need for electrofuels.

For the transport sector, it is found that liquid electrofuels provides lower energy system and fuel costs than gaseous electrofuels. Electromethanol has the lowest energy system costs, though the costs for electromethane is similar, but only until the cost of vehicles is added in the equation. Generally, methanol provides greater flexibility regarding storage and readiness to be upgraded to other fuels, namely jet fuels, which is a more complicated and energy-intensive process if it would be produced from methane. Fischer-Tropsch fuels may be an alternative if methanol-to-jet fuel pathways will not show sufficient technological maturity in the future.

Compared with producing CO₂-electrofuels, producing bio-electrofuels from biomass gasification results in significantly more biomass consumption in the energy system, but increases the efficiency of the energy system. Though both types of electrofuels are necessary for the future energy system despite the increased costs of CO₂-electrofuels as the fuels are limited by biomass availability and available CO₂-sources.

The results of the analysis indicate that syngas from biomass gasification can be a crucial fuel in combination with biogas both used for power, heat, or industrial purposes, at lower costs than electrofuels. Biogas should always have priority due to the lower cost, but since the agricultural sector outputs limit biogas, it must be complemented by syngas from biomass gasification. In addition, maximising on the use of lower-cost bio-electrofuels reduces the use of biomass for electricity generation, allowing the energy system to be more resilient to external electricity prices.

2 Introduction

The current Danish government has a goal of reducing the Danish CO₂-emissions to 70% of 1990 levels by 2030 and going to a climate-neutral country in 2050. For the energy sector, the 2050 goal means that the Danish energy system should be independent of fossil fuels in 2050, meaning that in Denmark the renewable energy production must be able to cover the Danish energy demands. Due to the long time horizon and the uncertainties related to technology development, no specific plans are created for how the energy system should look in 2050. However, based on the Danish tradition of different actors creating energy system scenarios in order to create a democratic discussion of how the transition to such an energy system could occur, several Danish actors have in recent years created different future energy scenarios with energy systems that can accomplish the political goals. Each of such scenarios is created using the available knowledge at the given time, and different actors focus differently on different parts of the energy system based on their knowledge and needs. Examples of different actors' energy system scenarios are the Danish Energy Agency's "Energy scenarios for 2020, 2035 and 2050" from 2013 [3], the Danish Society of Engineers (IDA) "IDA's Energy Vision 2050" from 2015 [1], and Energinet's "System Perspective 2035" from 2018 [2].

The purpose of the work presented in this report is to utilise existing energy system scenarios from different Danish actors, thereby eliminating or reducing the potential bias from the energy scenario developers in order to analyse how different technologies could affect different types of future energy systems where renewable technologies supply all energy demands. A special focus is on power-to-heat (P2H) and power-to-gas (P2G) technologies, though the scope is not limited to these technologies. It is essential to have scenarios that both investigate the long-term 2050 energy system, but also include a shorter-term perspective, as different technologies might have different roles in a 100% renewable energy system than in energy systems with a lower share of renewable energy. In turn, this is useable for policy considerations in regards to which technologies should be implemented early and which should wait until the share of renewable energy in the energy system is higher, and which technologies are only relevant in the transition towards 100% renewable energy. Not all potential technologies are investigated in this.

In this report, it has been chosen to use energy system scenarios from "IDA's Energy Vision 2050" from 2015 [1] and Energinet's "System Perspective 2035" from 2018 [2]. The energy system scenarios in both of these reports include all energy sectors, though they detail the different parts of them differently, and both use the years 2035 and 2050 as modelling years, meaning that they have the same years for a medium- and long-term outlook.

Energinet is the Danish national transmission system operator of the electricity and gas networks. The scenarios in Energinet's "System Perspective 2035" from 2018 function as the medium- and long-term outlook for Energinet, used for planning future investments in infrastructure, developing the market design and operation strategies, and as a contribution to public and political discussions. The scenarios were developed using input data from ENTSO-E's "Ten Year Network Development Plan" (TYNDP) from 2018 to project the development in the surrounding countries. Based on TYNDP from 2018, Energinet states three different scenarios for the potential future Danish energy system to understand the consequences of the potential developments. The three scenarios in "System Perspective 2035" are:

- **Global climate action (GCA)**, where Europe is ambitious concerning the green transition with a strong collaboration between the countries.

- **Distributed Generation**, also an ambitious green transition, but more national, local, and individual solutions that are used for the transition.
- **Sustainable transition (ST)**, the least ambitious green transition scenario, but with increased amount of wind power and PV due to decreasing costs of these technologies.

In this work, only the ST and GCA are used, as these represent different European transition ambitions.

IDA regularly publishes scenarios for the future Danish energy system, with the first one published in 2006 and the newest published in 2020. The scenarios cover different years, with the newest “IDAs Klimasvar” currently only covering the 2030 70% CO₂-emission reduction target. The most recent energy system scenario covering 100% renewable energy in 2050 is “IDA’s Energy Vision 2050” from 2015 that includes both a scenario for the long-term 2050 goal, but also have a medium-term scenario for 2035 [1]. As such, “IDA’s Energy Vision 2050” is used in these analyses with the updates described in [4] and Appendix G. IDA’s energy system scenario is developed based on the concept of Smart Energy System, in which synergies between energy sectors are exploited to increase energy efficiency and reduce costs [5]. Besides changes to the energy transformation, the scenario also includes significant energy savings at the end-users.

Besides the three future energy systems scenarios, a short-term energy system for the Danish energy system in 2020 is also developed based on the Danish Energy Agency’s frozen policy projection from 2018. This 2020 scenario is used as a representation of the current Danish energy system and is used for comparing how future energy systems vary from the current Danish energy system. The 2020 scenario is as such, not the focus of the analyses. The details of the 2020 scenario can be found in Appendix E.

2.1 Comparison of energy system scenarios

In this section, the ST, GCA and IDA energy system scenarios are compared in terms of their energy generation mix. All numbers shown in this chapter are based on the values from the original simulation tool used for creating each scenario. The electricity generation mix, including import of electricity in each of the three energy system scenarios, is compared in Figure 2.

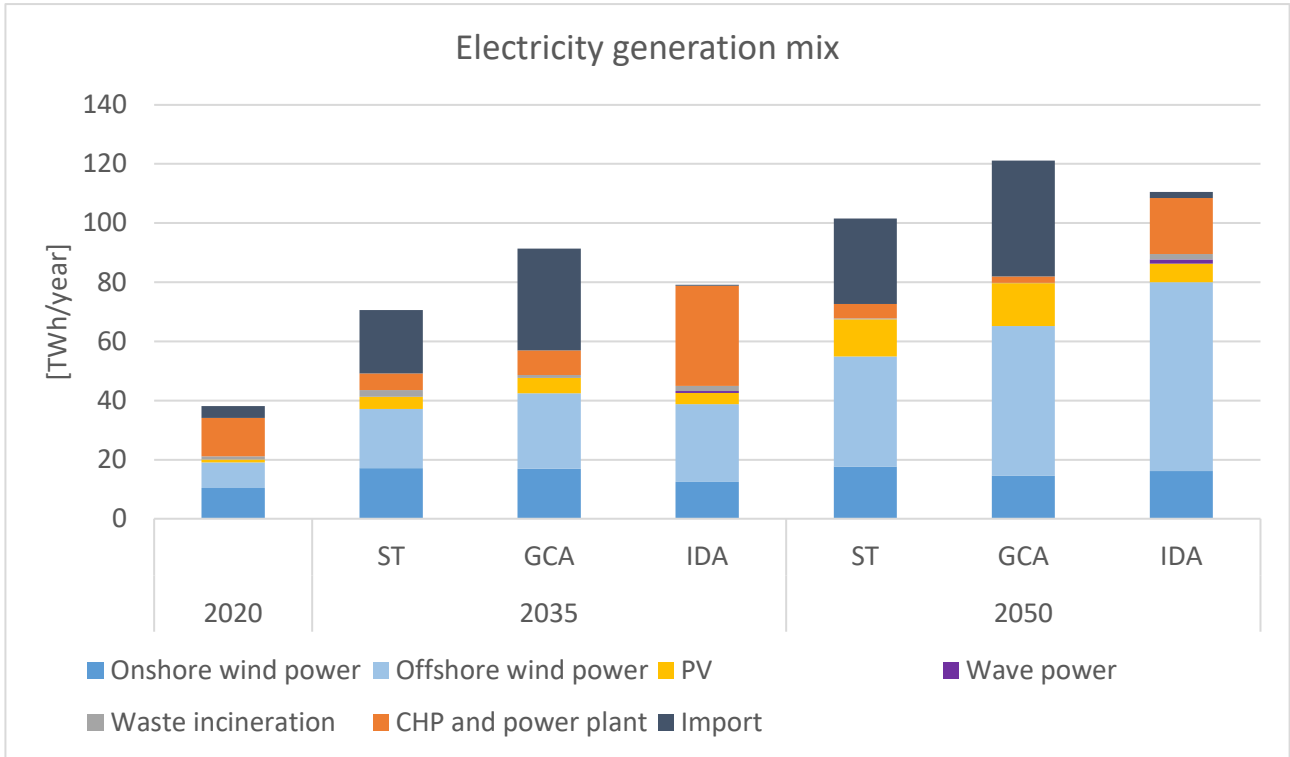


Figure 2 – Electricity production for the different energy system scenarios divided into the type of production unit

As shown in Figure 2, all scenarios show an increasing utilisation of variable renewable energy (VRE) for electricity production, mostly as wind power and solar photovoltaic (PV). The ST and GCA energy system scenarios are highly dependent on the import of electricity from neighbouring countries, whereas the IDA energy system scenario aims at meeting most of the national electricity demand by domestic electricity-producing units. Accordingly, the share of thermal power and combined heat and power (CHP) plants in the IDA energy system scenario is significantly higher than the ST and GCA energy system scenarios. Another key difference is in the share of PV in 2050; GCA and ST include more than double PV-based electricity production than is installed in the IDA scenario. While all three energy system scenarios have a large share of offshore wind power in 2050, the share of this technology varies a lot across the scenarios, from approximately 59% of the electricity production in IDA to 38% in ST. The electricity generation mix shows large differences across the three energy system scenarios while being consistent between 2035 and 2050 in each scenario.

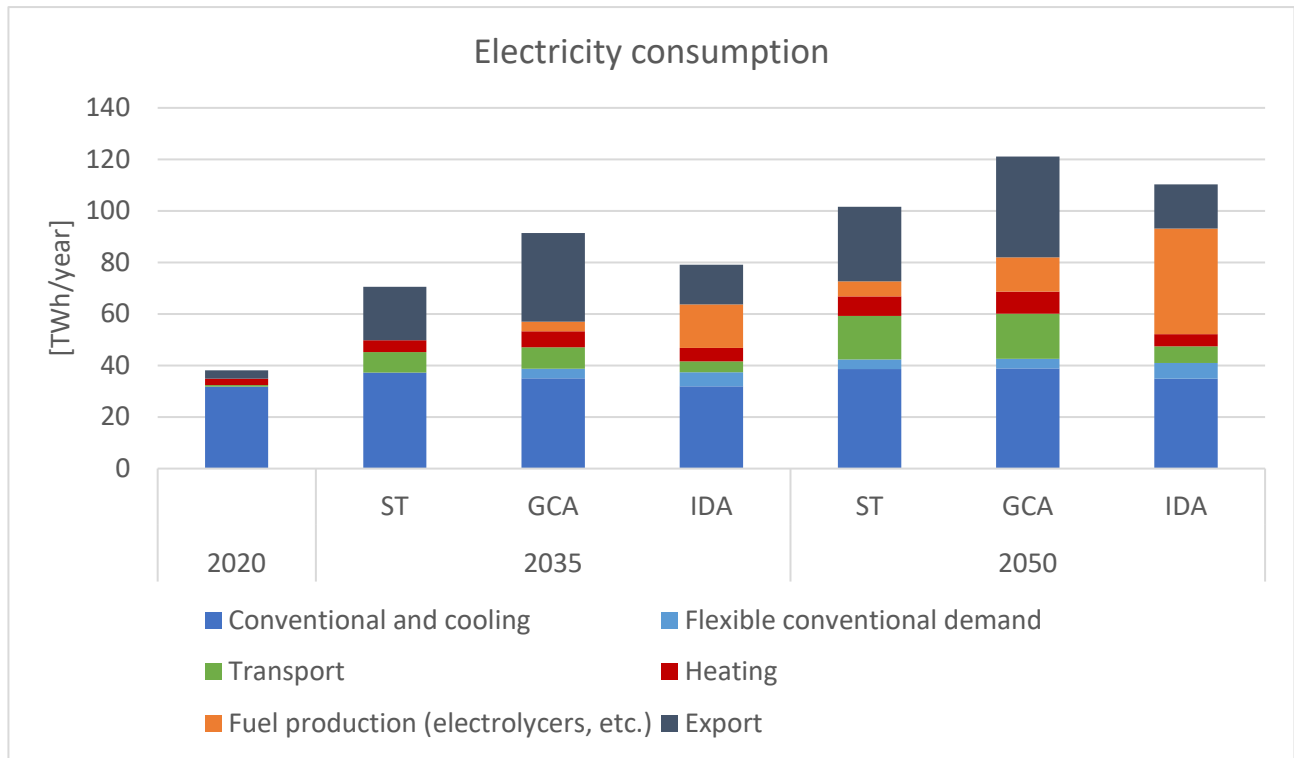


Figure 3 – Electricity consumption for the different energy system scenarios based on the type of consumption

Figure 3 shows the electricity consumption and export of electricity from the Danish energy system. It shows that the ST and GCA energy system scenarios have a more extensive export of electricity compared with the IDA scenario; a pattern similar to the electricity imports observed in Figure 2. However, the ST and GCA scenarios propose a balanced electricity exchange: the net import of electricity is 0.61 and 0.01 TWh/year in ST2035 and ST2050, respectively, and 0.04 and 0.06 TWh/year in GCA2035 and GCA2050, respectively. In the IDA scenario, the Danish electricity system is a net exporter, with 15.14 and 15.08 TWh/year exports to the neighbouring countries in 2035 and 2050, respectively. One of the main reasons for this difference between IDA and other two energy system scenarios is due to the large capacity of flexible CHP and power plants in IDA, 6 GW compared to less than 2.1 GW in ST and GCA in 2050. The thermal plant utilised in IDA are assumed to be highly efficient, and so able to export electricity in many hours of the year due to a low electricity production price, relative to the electricity market price in the main price scenario.

The comparison in Figure 3 also reveals that electricity for fuel (electrofuel) production, e.g. in form of P2G, through electrolysis is considerable in all energy system scenarios, especially in IDA2050, where electricity used by electrolyzers to produce hydrogen for use in the production of other fuels comprises the largest part of the electricity end-use. On the other hand, the ST and GCA scenarios include more direct electrification of the transport sector compared to the IDA scenario. Also, the ST2050 and GCA2050 scenarios include yearly net import of liquid fuels of 5.1 TWh in ST2050 and 3.35 TWh in GCA2050. For gas, the ST2050 has a yearly net import of 5.18 TWh, where the GCA2050 has a yearly net export of gas of 5.45 TWh. The IDA2050 scenario is built around a yearly net import of liquid fuels and gas of zero.

Figure 4 shows the individual heating production in all energy systems scenarios.

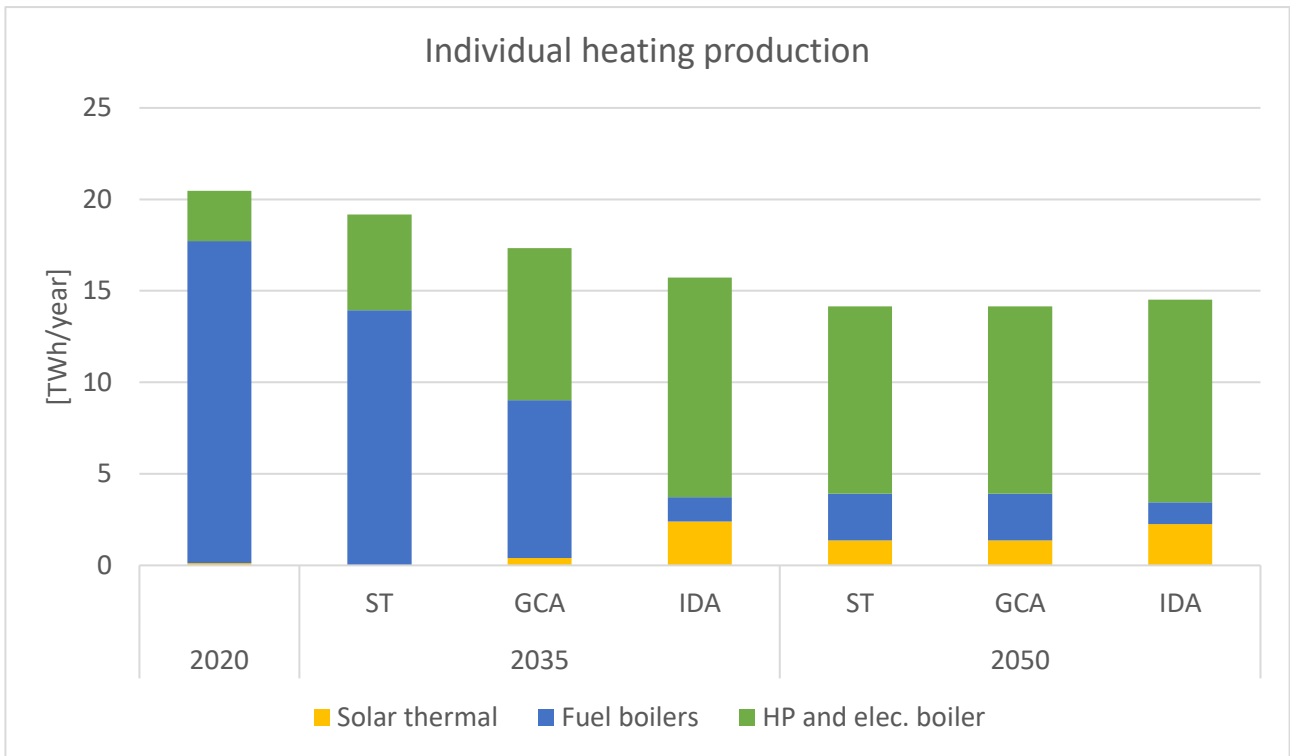


Figure 4 – Individual heating production for the different energy system scenarios divided into the type of production units. HP is short for a heat pump.

As depicted in Figure 4, all the energy system scenarios utilise individual electric-driven heat pumps (HP) as the primary heating solution for individually heated buildings in 2050, being an important P2H technology. Similarly, the total individual heating demand is similar in 2050 across the three scenarios. IDA includes more solar thermal than the other two scenarios. The heating solutions in 2035 show a more considerable structural difference between the scenarios. While the individual heating mix in IDA, like 2050, is mainly based on HPs, the ST scenario, and to a lesser extent the GCA scenario, rely on fuel-burning boilers for individual heating. The fuel boilers are mostly biomass boilers, though with a share of gas-fired boilers in the ST and GCA scenarios.

Figure 5 shows district heating (DH) production in the three energy system scenarios.

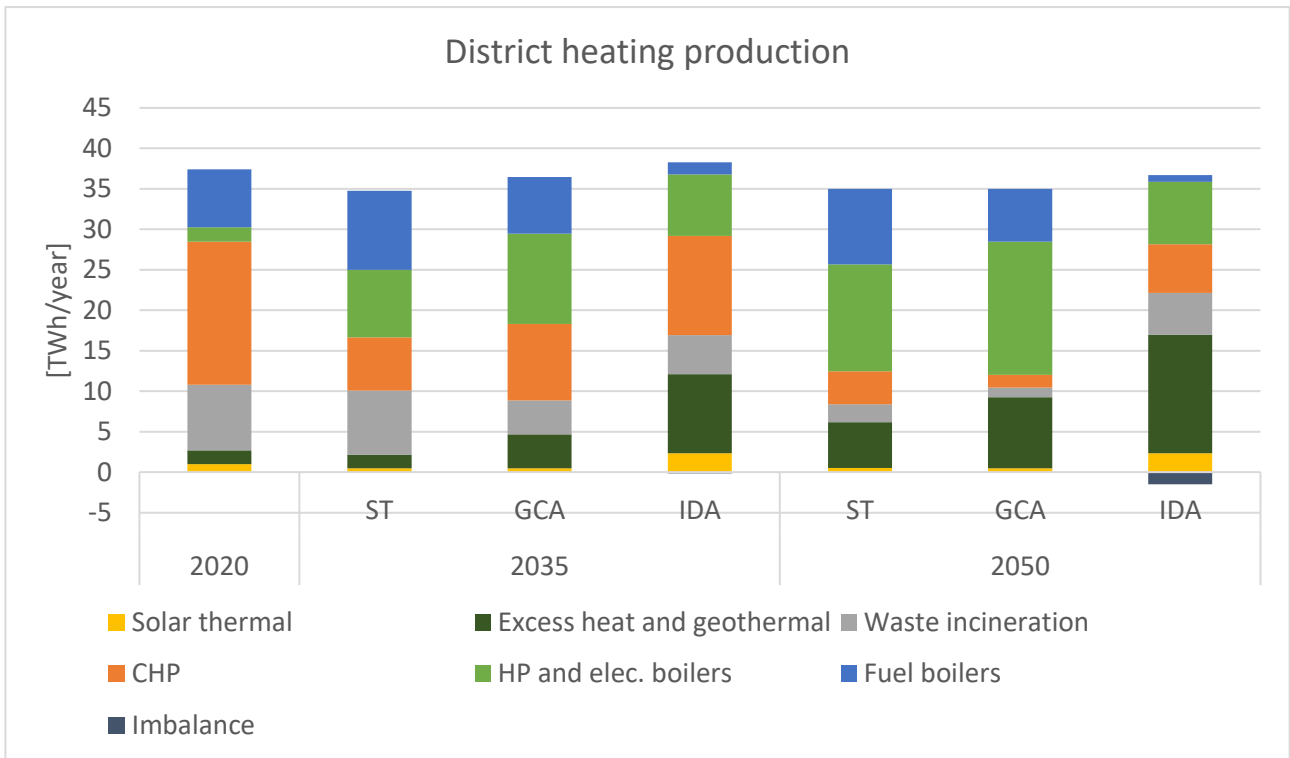


Figure 5 – DH production for the different energy system scenarios divided into types of production units. Imbalance represents the surplus heat that is produced but cannot be utilised in the DH system. HP is short for heat pump

As shown in Figure 5, the three scenarios have similar projections for the DH demand in both 2035 and 2050 with the DH demands in 2050 being almost the same. However, the production of DH is significantly different between the scenarios, wherein IDA excess heat and geothermal are used extensively, the other two energy system scenarios have electric-driven HPs as the largest producers of DH, again being an important P2H technology. The IDA scenario also utilises considerable more solar thermal for DH, which sees an expansion towards 2035, where the ST and GCA scenarios do not include an expansion of solar thermal for DH. The ST and GCA scenarios utilise biomass boilers installed at DH to a much larger extent than the IDA scenario, both in 2035 and in 2050.

3 Modelling testbed

The scenarios are used in the modelling testbed, where the scenarios are set up and adjusted to make them comparable without changing the main aspects of each scenario. More specifically, all scenarios are modelled in the same energy system modelling tool, and all costs are updated so that they are using the same updated technology data. The reason for this is to make a modelling testbed setup that allows for a direct comparison between the scenario results to the extent possible. A direct comparison might not be possible in all cases, as Energinet and IDA have had different focuses in their scenario development, they have detailed different aspects of the energy system differently. Where Energinet focuses on the electricity and gas systems and these systems' connections to the surrounding countries, IDA focuses more on the possibilities within the Danish energy system, and as such have more details about, e.g. energy savings, transport and expansion of DH.

3.1 Energy system modelling tool

When analysing future energy systems, modelling tools are essential to quantify the temporal operation of the different parts of the energy system. This is especially important with the increased use of VRE, such as wind power and PV. All the scenarios in the modelling testbed have been developed in different energy systems modelling tools with an hourly temporal resolution.

The ST and GCA scenarios were developed in Energinet's internally developed energy system modelling tool "Sifre-Adapt" [2], which consist of two individual modules; Sifre [6] and Adapt [7]. The module 'Adapt' decides optimal investments into infrastructure and technologies, based on e.g. framework conditions, and is thereby used for setting up the different scenarios for the Danish energy system. The module Sifre is an energy system simulation tool where the hourly operation of an energy system can be simulated. Sifre focuses on the electricity and heating sectors but can include more sectors. In Sifre an energy system can be defined into different geographical areas with transmission limitations between these, where in the ST and GCA scenarios Denmark has been divided into 8 such areas. In each of these areas types of energy conversion plants are established that should demonstrate the dynamics of the interaction between electricity, gas and heat at large-scale and small-scale energy plants.

The IDA scenario was developed by using the energy system modelling tool EnergyPLAN, that have been used for many research publications in relation to transforming local, regional, national and transnational energy systems towards more renewable energy source (RES) [8]. EnergyPLAN can simulate hourly energy balances in all the sectors in an energy system, including the heating, power, gas, transportation, and water desalination sectors. In EnergyPLAN, the energy system is represented as a copper-plate model in terms of the electricity and gas system with no spatial specification of the location of demands and supply within the modelled system. However, connections to other countries are included as a single transmission connection. DH systems are represented as two distinct entities; being small-scale and large-scale DH systems that are not connected. Though the spatial information is not represented in the EnergyPLAN model, the input values are based on spatial analyses [1]. The overview of technologies and sectors present in EnergyPLAN is shown in Figure 6.

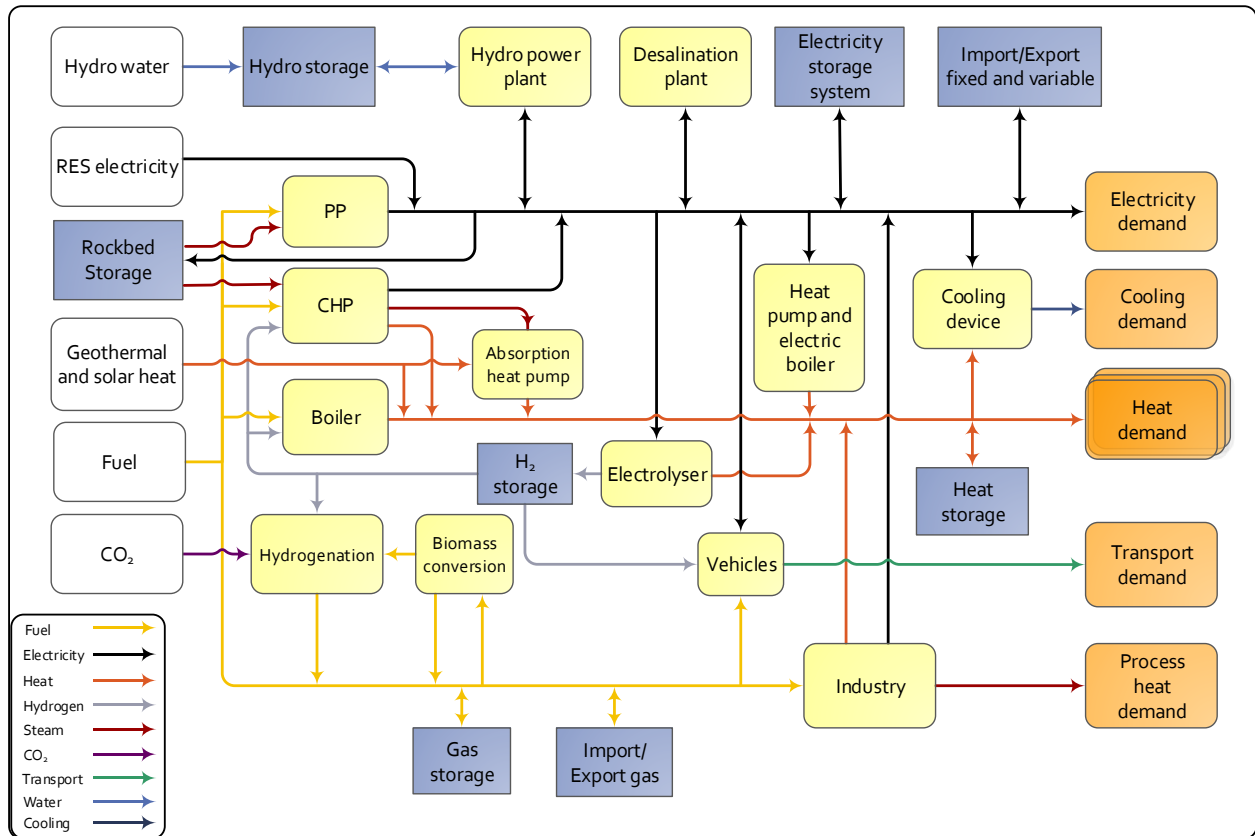


Figure 6 - Overview of EnergyPLAN technologies and cross-sector integration [9]

Based on the effective use of EnergyPLAN for analyses of the Danish energy system, that it is freely available to use and its ability to simulate all energy sectors, it has been chosen to use EnergyPLAN for the modelling testbed. As IDA already is designed in EnergyPLAN, only the ST and GCA scenarios must be adapted into EnergyPLAN. ST and GCA are designed in Sifre-Adapt model, and due to differences between Sifre-Adapt-model and EnergyPLAN, some differences in the simulation results are expected. However, efforts are made to build models and run simulations in EnergyPLAN consistent with the original energy systems developed using the Sifre-Adapt-model so that the output of the two models stand as close as possible.

The versions of the ST and GCA implementation into EnergyPLAN are done using the data described in appendix A, B, C, and D. A comparison between the Sifre-Adapt versions and the EnergyPLAN versions is shown in the following section, where the original costs from Sifre-Adapt are used, to make the versions comparable.

3.2 Effects of implementing ST and GCA into EnergyPLAN

In this section, the effects of converting the ST and GCA scenarios from Sifre-Adapt to EnergyPLAN are analysed. The comparison is made by using the same capacities, yearly demands and variable costs as was used in Sifre-Adapt; however, due to differences in simulation approaches and level of details between the two simulation tools, some differences in the operation of the energy system scenarios between the two tools are to be expected. Also, it has not been possible to obtain hourly operational inputs or hourly results from

the Sifre-Adapt simulations. As such, the implementation into EnergyPLAN and the corresponding comparison are based on yearly inputs and results to and from Sifre-Adapt. For demands, productions and international electricity prices, where an hourly profile is needed, the hourly distributions from the IDA scenario have been used, which also creates a potential for differences between the original Sifre-Adapt simulations and the IDA scenario. The full list of used hourly distributions can be found in appendices A-D, but among the hourly distributions are heat demands, electricity demands, wind power production, and international electricity market prices. The version of EnergyPLAN used is v15.1.

Figure 7 shows the energy balance for the two scenarios in 2035 and 2050, where both the original Energinet scenario results from Sifre-Adapt and the results of the implementation into EnergyPLAN are shown.

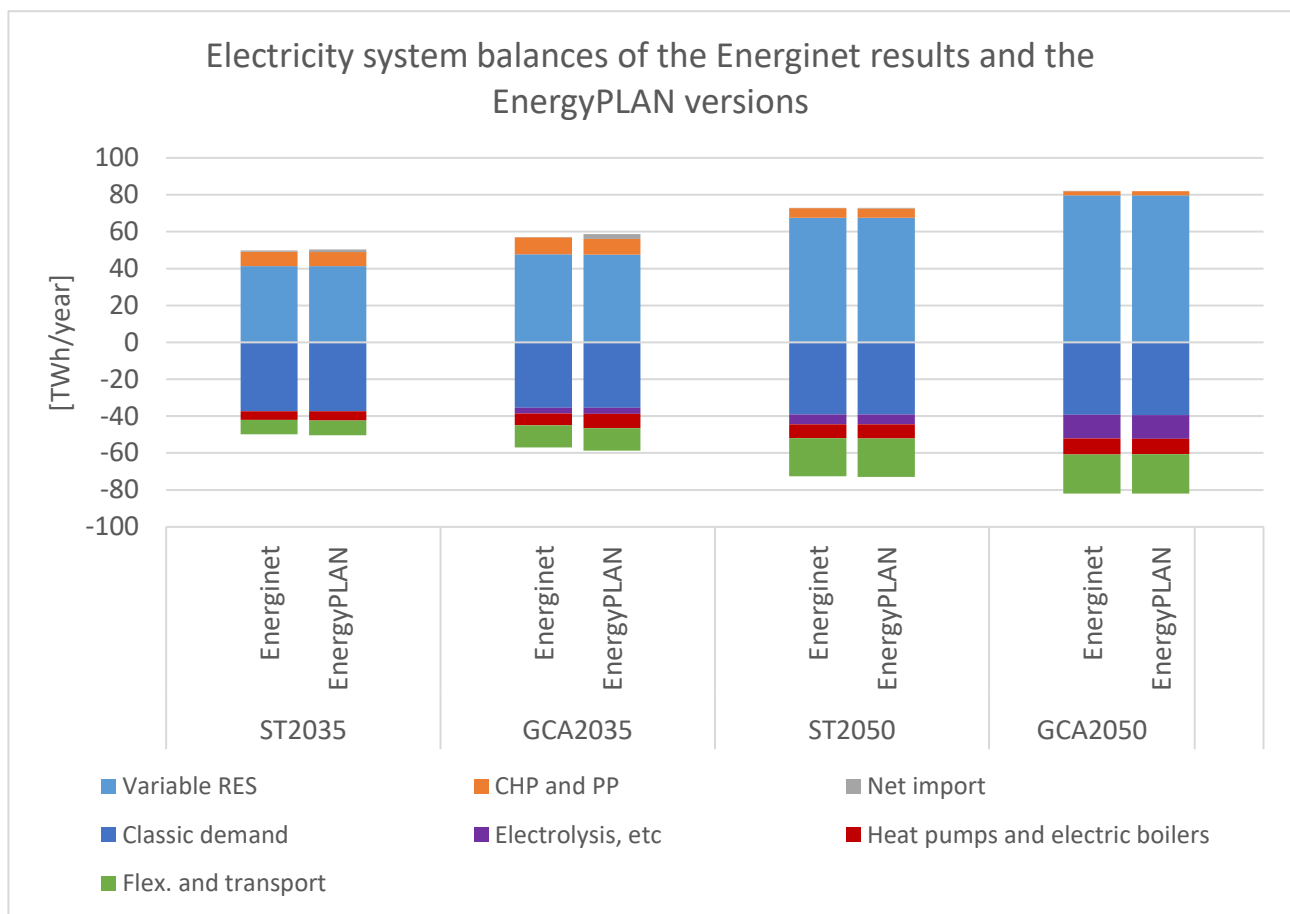


Figure 7 – Electricity system balances for the ST and GCA scenarios. Both the original Energinet results and the results of the EnergyPLAN version of the scenarios are shown for comparison. Electricity production is shown as a positive value and consumption as a negative. “Flex. and transport” includes flexible electricity demand and transport.

As shown in Figure 7, in most cases, the overall electricity balances are similar. Especially the two 2050 scenarios show similar results in the Sifre-Adapt and EnergyPLAN simulations, where the ST2050 only has a minor difference in the HPs and electric boilers consumption that is 0.2 TWh higher in the EnergyPLAN simulation compared with the Sifre-Adapt results, and this results in a 0.2 TWh higher import to the energy system. For the GCA2050 scenario, there are some minor differences in that the HPs and electric boilers consumption consume about 0.2 TWh less electricity, and the category “Flex. and transport” consume about 0.1 TWh more in the EnergyPLAN version, resulting in a reduction in the import of electricity of about 0.2 TWh. These minor

differences can be due to the differences in the hourly distribution of demands, production of VRE and international electricity prices.

The differences are somewhat more considerable in the two 2035 scenarios, wherein the ST2035 scenario the CHP and PP produce about 0.3 TWh less electricity and the HPs and electric boilers consume 0.5 TWh more electricity in the EnergyPLAN version, increasing the import of electricity of about 0.9 TWh. In the GCA2035 scenario, the CHP and PP produce about 0.8 TWh less, and the HPs and electric boilers consume 1.6 TWh more in the EnergyPLAN version, increasing import of 2.5 TWh. Besides the minor differences in the 2050 scenarios, it is expected that the main reason for these larger differences in the 2035 scenarios compared with the 2050 scenarios are due to the differences in the level of aggregation in which the two energy system analysis tools simulate. Due to being intermediate scenarios, the 2035 scenarios have a wider variety of plants than the 2050 scenarios, and as such, the 2035 scenarios are more affected by differences in the used level of aggregation compared with the 2050 scenarios. In EnergyPLAN plants are aggregated into decentral and central plants, whereas in Sifre-Adapt both the decentral and central plant categories consist of several different plants with different production technologies. As such, EnergyPLAN utilises desirable technologies to a more considerable extent, as the aggregation does not limit production from these technologies to the same extent as Sifre-Adapt does.

As discussed, the differences between the Sifre-Adapt and EnergyPLAN results are mostly related to units delivering DH, and it is, therefore, essential to closely examine the differences in DH production. Figure 8 shows the DH production for the two scenarios in 2035 and 2050, where both the original Energinet scenario results from Sifre-Adapt and the results the implementation into EnergyPLAN are shown.

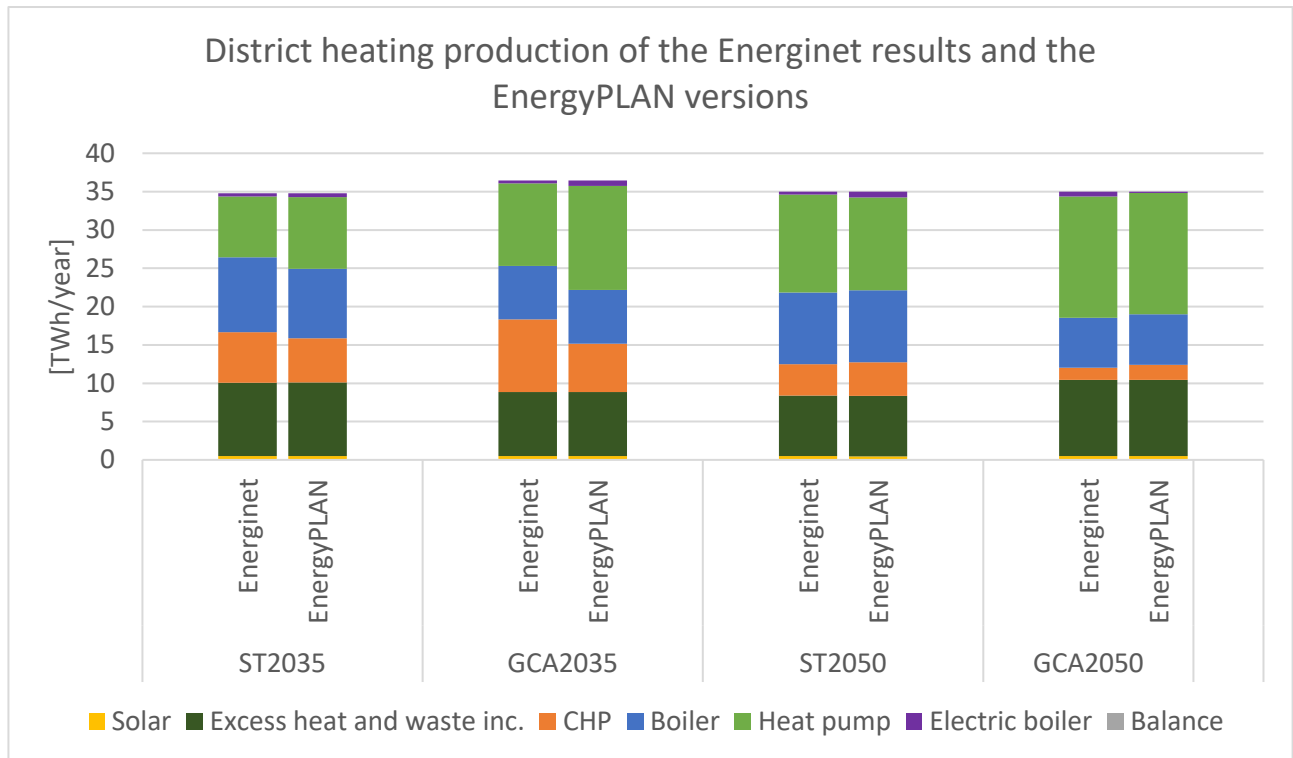


Figure 8 – DH production in the ST and GCA scenarios. Both the original Energinet results and the results of the EnergyPLAN version of the scenarios are shown for comparison.

Similarly to Figure 7, Figure 8 also shows more considerable differences between the 2035 scenarios than between the 2050 scenarios. In the 2035 scenarios, it is mainly the HP that operates more in the EnergyPLAN version compared with the Sifre-Adapt version, wherein ST2035 they produce 1.4 TWh more DH and in the GCA2035 they produce 2.8 TWh more compared with the Sifre-Adapt version. Likewise, the electric boilers produce more DH in the EnergyPLAN versions, wherein the ST2035 scenario they produce 0.1 TWh more, and in the GCA2035 scenario, they produce 0.3 TWh more. This higher production of DH from the electricity consuming units results in reduced CHP and fuel boiler production, wherein ST2035 the CHP units produce 0.8 TWh less heat and the fuel boilers produce 0.7 TWh less heat, and in the GCA2035 scenario, the CHP produces 3.2 TWh less heat.

In the ST2050 scenario, the HPs produce about 0.7 TWh less DH in the EnergyPLAN version, which results in more DH production on the CHP produce about 0.3 TWh more, the fuel boilers 0.1 TWh more, and the electric boilers about 0.4 TWh more. In the GCA2050 scenario, the electric boilers produce about 0.5 TWh less in the EnergyPLAN version, with this DH production instead of being delivered by about 0.4 TWh CHP and about 0.1 TWh fuel boiler production.

Figure 9 shows the resource consumption for the Danish energy system for the ST and GCA scenarios in 2035 and 2050, where both the original Energinet scenario results from Sifre-Adapt and the results the implementation into EnergyPLAN are shown.

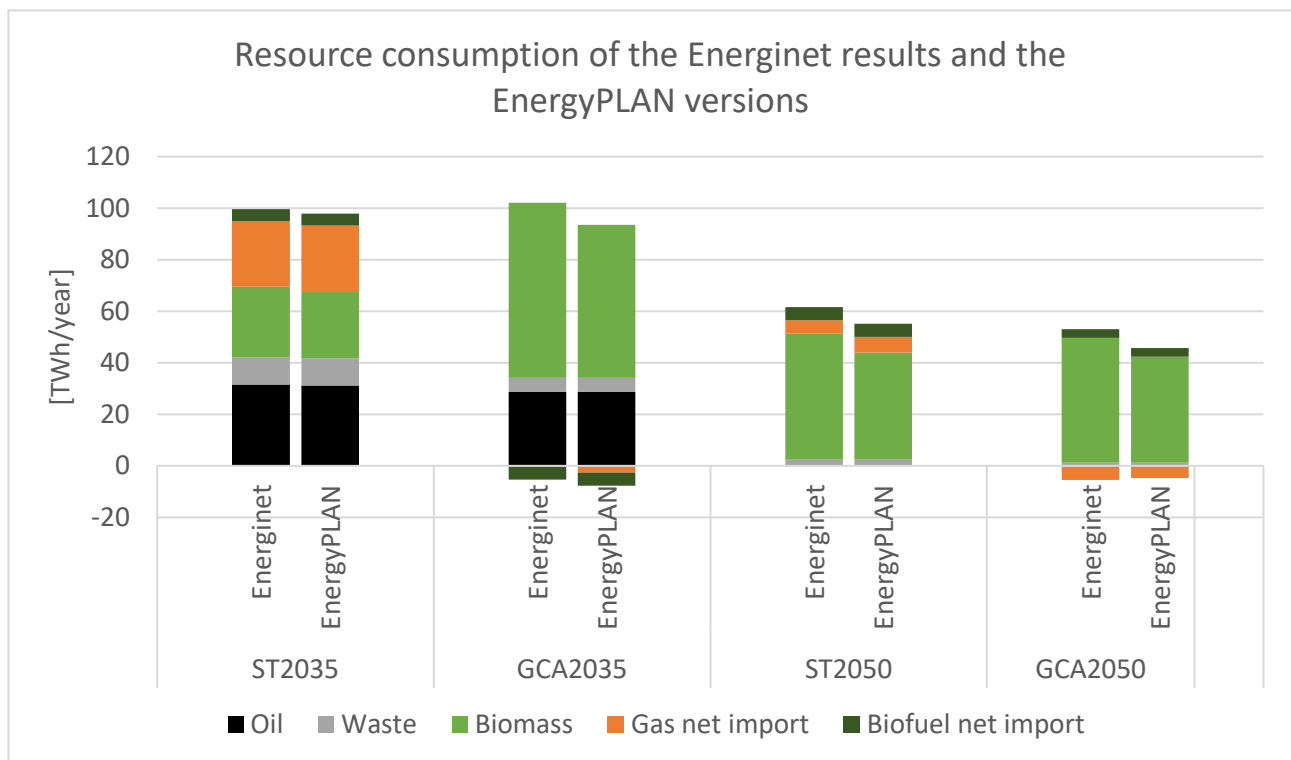


Figure 9 – Resource consumption of the ST and GCA scenarios. Both the original Energinet results and the results of the EnergyPLAN version of the scenarios are shown for comparison. For biogas, the input into the biogas facilities is used for calculating the biomass consumption for biogas production shown in the figure.

As shown in Figure 9, the resource consumption shows similar tendencies, as shown in Figure 7 and Figure 8. The main difference between the two simulations of the 2050 scenarios is due to the differences in the operation of the electricity and DH producing units, resulting in the net import of gas increases, wherein the ST2050 it is 1 TWh higher in the EnergyPLAN version compared with the Sifre-Adapt version and in the GCA2050 it is 0.8 TWh higher. In addition, due to the differences shown in Figure 7 and Figure 8, the biomass consumption in the GCA2050 is 0.2 TWh higher in the EnergyPLAN version.

In the ST2035 scenario, the main difference is the biomass consumption, which is 1.7 TWh lower in the EnergyPLAN version. Besides that, there is also a 0.4 TWh lower oil consumption and a 0.3 TWh higher gas consumption. All these are related to the difference in the production of electricity and DH. For the GCA2035 scenario, the biomass consumption is 1.2 TWh lower, and the net import of gas is 2.4 TWh lower in the EnergyPLAN version compared with the Sifre-Adapt version. These differences shown in Figure 9 are expected to be due to the differences in input data and tool model approach, as discussed earlier.

3.3 Adjustments of costs in the scenarios

Before using the scenarios in the modelling testbed, the scenarios are updated to use the same cost assumptions for investments, variable operation and maintenance (OM) costs, fixed OM costs, fuel costs, and prices on the external electricity markets. The overview of the investment, fixed OM and variable OM costs used in the modelling testbed can be found in Appendix F.

Fuel costs and prices on the external electricity markets from “IDA’s Energy Vision 2050” [1] are used. In this publication there are three different fuel price levels being low, medium, and high. These are used alongside five electricity market price levels of 16, 31, 47, 62, and 77 EUR/MWh, from the same publication. If no other information is given, the used fuel price level used is the medium fuel price level and the electricity market price level used is the 47 EUR/MWh.

Where the ST and GCA scenarios have been developed based on other fuel prices, the IDA scenario results shown are using the medium fuel price level. For electricity market prices the ST and GCA scenarios have been based on electricity market prices of about 47-49 EUR/MWh, whereas for the results of the IDA scenario shown in section 2.1, 77 EUR/MWh has been used. The comparison of the three different scenarios in section 2.1 has thereby been based on both different energy system modelling tools, but also different prices that affect the operation of the units in the energy systems. In this section, all scenarios are adjusted to using the same fuel prices, and all are modelled in EnergyPLAN, as the ST and GCA scenarios described in the previous section. The parts of the energy system where the conversion of energy will be affected by yearly changing costs are the electricity system and DH systems, which is the focus of this section.

Figure 10 shows the electricity system balances for the scenarios with the old and new costs, with demands shown as a negative and production shown as a positive value.

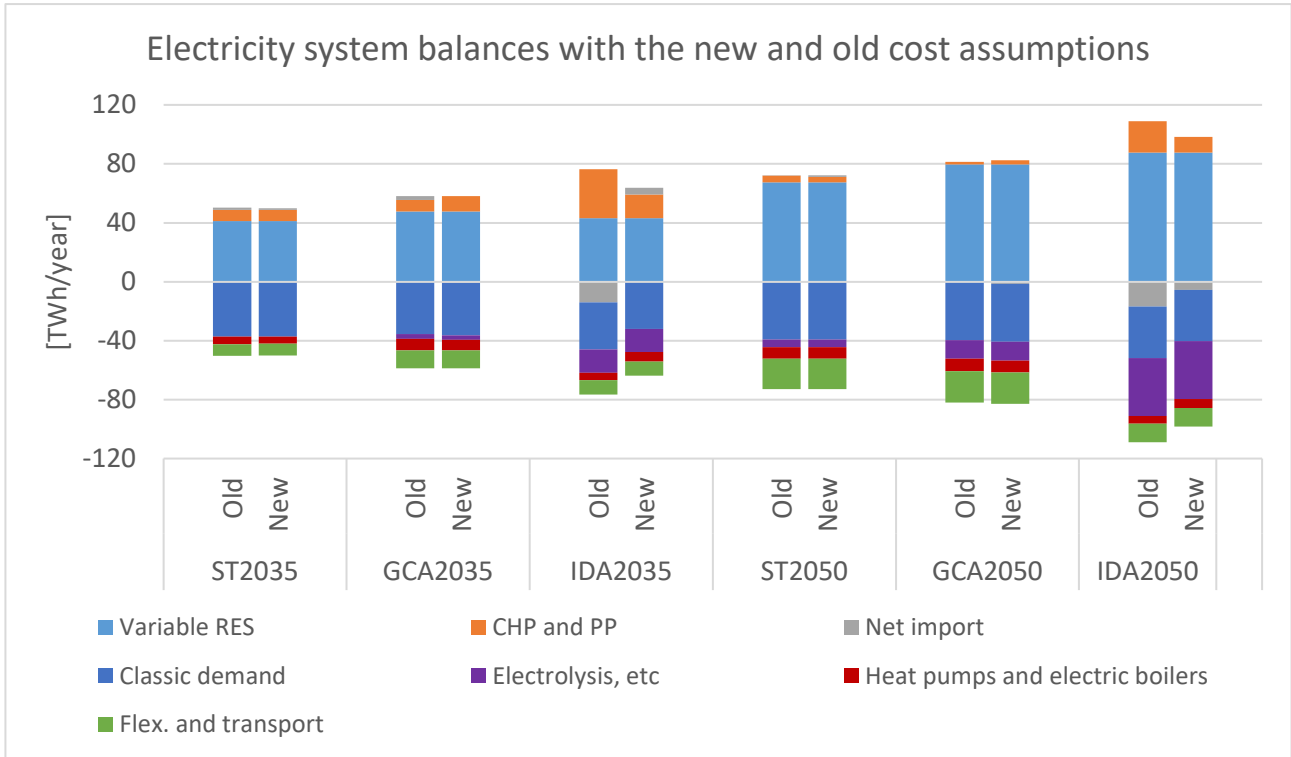


Figure 10 – Electricity system balances for each scenario using old and new costs that affect the variable production of energy, being fuel, variable OM, and electricity market costs. Electricity production is shown as a positive value and consumption as a negative. “Flex. and transport” includes flexible electricity demand and transport.

As shown in Figure 10, the differences in the ST and GCA scenarios are relatively minor, whereas the difference in the IDA scenario is more significant. The major difference in the IDA scenario is a reduced electricity market price level from 77 EUR/MWh to 47 EUR/MWh, which in turn affects the import and export of electricity to the energy system as the CHP and power plants are operated less with the lower electricity price level.

Figure 11 shows the DH production for the scenarios with the old and new costs.

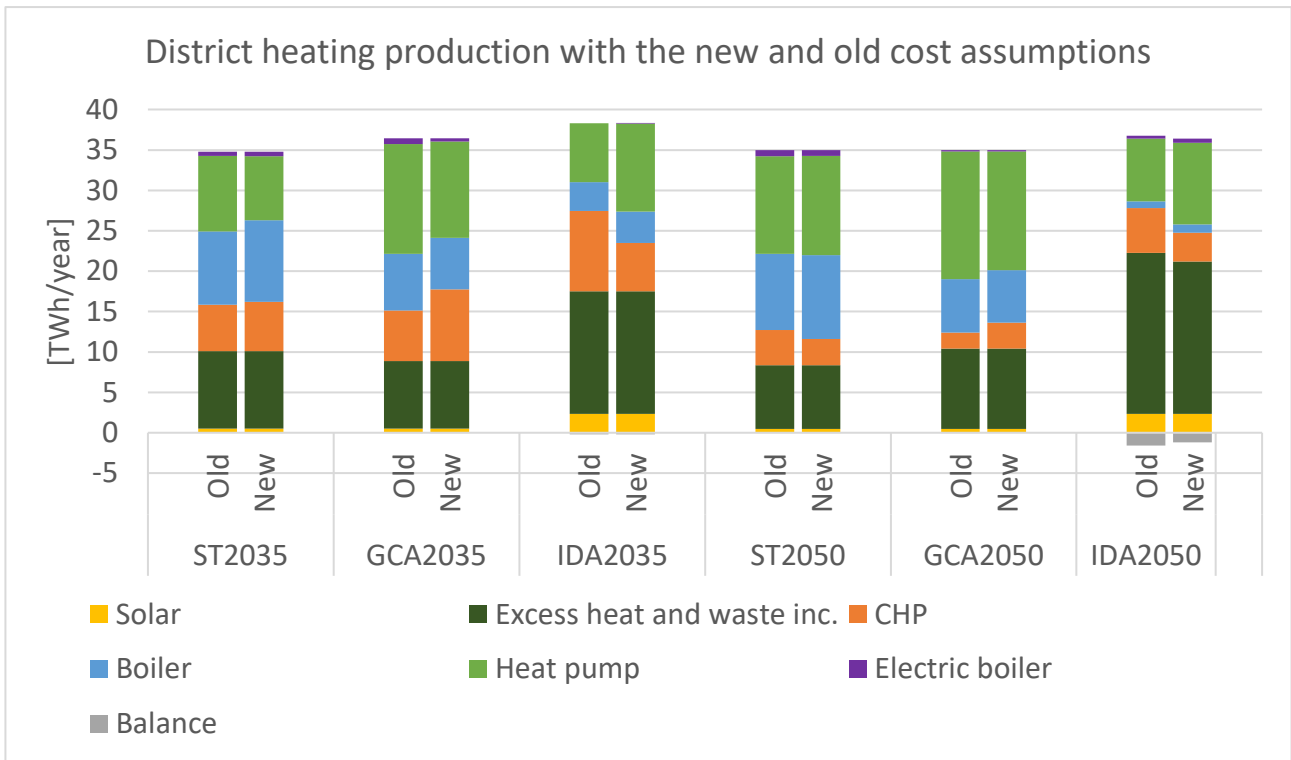


Figure 11 – DH production for each scenario using old and new costs that affect the variable production of energy, being fuel and electricity market costs.

As shown in Figure 11, the CHP DH production is affected by the updated costs, with reductions seen in IDA scenario and ST2050, whereas an increase is seen in GCA2035 and GCA205, with a minor increase in ST2035. Again, the electricity market price reduction in the IDA scenario is the reason for this change in that scenario. The changed DH production from CHP means that especially the HP and fuel boilers production is changed accordingly to ensure the supply of DH.

Figure 12 shows the energy resources used in the energy system, being energy resources like oil, waste, biomass, and gas.

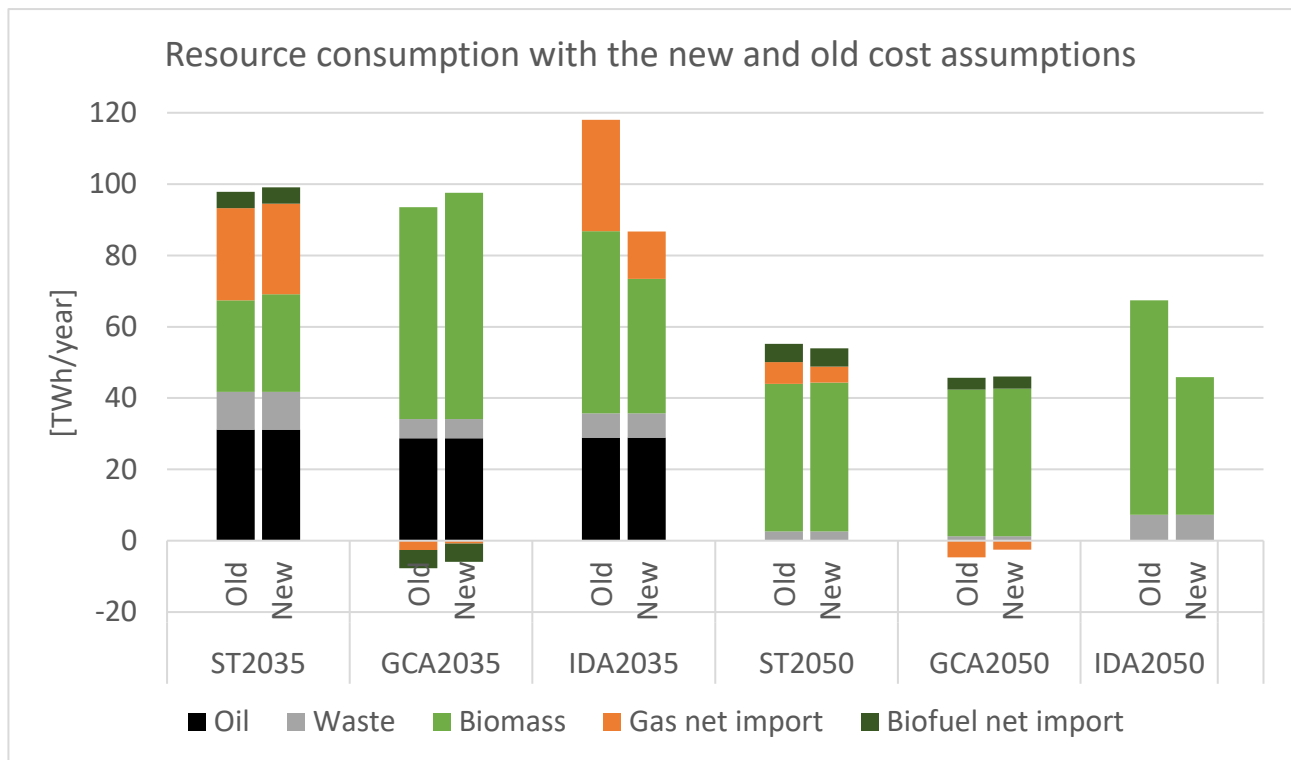


Figure 12 – Resource consumption for each scenario using old and new costs that affect the variable production of energy, being fuel and electricity market costs.

As shown in Figure 12, it is mostly the use of biomass and gas affected by the update of costs. This is directly related to the operation of the CHP and power plants in the energy system, which is also why the most considerable differences are seen for the IDA scenario, as that has the largest share of CHP and power plant operation in the original simulations.

3.4 Method for the analyses

Having set up the modelling testbed, the scenarios are used for analyses of how different technologies can affect the future Danish energy system based on RES. The analyses are grouped into four overall categories. The four categories are:

- Operational analyses of the scenarios – being operational analyses of the scenarios without changes to technologies used.
- Electrification – being analyses with a focus on the electricity system.
- Heat sector – being analyses focusing on the individual and DH systems.
- Renewable fuels in the Danish energy system – being analyses focusing on the role and production of different renewable fuels.

The categories do not only include the effects within their focus area, but includes the effects in other energy sectors, e.g. CHP is shown in the Heat sector category, but as CHP produce both the electricity and heating sectors it also directly affects the electricity system. In the operational analyses, the hourly operation of the scenarios, as simulated in EnergyPLAN, is analysed. As such, this part does not include any changes to the scenarios except that described in sections 3.2 and 3.3. In the last three categories, variants of the scenarios

are created by changing different technologies in the scenarios to investigate the overall energy system effects. In each of the chapters of the last three categories there first is described relevant existing research within the category, which is used for identifying relevant areas and technologies for investigation. The existing research is followed by the analyses and discussions of the simulation results.

The three energy system scenarios are mainly compared to each other in terms of total annual costs, primary fuel supply, biomass consumption, and import/export of energy. However, as not all metrics are equally relevant for all variants, there are differences in the used metrics in the different analyses.

When analysing the different variations in the three energy system scenarios, it is crucial to ensure a consistent method for comparison that ensures sufficient energy supply for the energy systems simulated. As all three scenarios gain most of the primary energy from offshore wind power, which can also be seen as the marginal installed unit, as the offshore wind power produces throughout the year in Denmark and the technical potential for offshore wind power capacity could be up towards 40 GW in the Danish waters [10]. As the largest installed offshore wind power capacity in any of the scenarios is 14 GW in the IDA2050 scenario, then there is plenty of potential to expand the offshore wind power capacity in any of the scenarios if need be. As such, offshore wind power capacity is adjusted in each scenario when a variation is made to the scenario. The choice of a new offshore wind power capacity is based on the critical excess electricity production (CEEP). CEEP is the electricity produced that cannot be utilised, stored, or transmitted to other areas at the time of production. CEEP is mostly a relevant metric in energy system simulation tools as such an overproduction of electricity in a real-life energy system would result in grid instabilities, and as such, in real life energy systems CEEP can be avoided, e.g. by reducing the production of wind power in periods. First, the CEEP is identified in the unchanged scenario but without transmission capacity to other countries installed. Then the adjustments are made to the investigated technologies in the scenario, and the offshore wind power capacity is then adjusted until reaching the same level of CEEP as in the original scenario without transmission capacity. In this process, it is also ensured that any scenario principles used in the development of the original scenarios are maintained, which mainly is related to the IDA2050 scenario that has been developed based on a principle that all gaseous and liquid fuels must be produced within the Danish energy system when seen on a yearly basis.

4 Operational analyses of the scenarios

In this chapter, the hourly operation of the scenarios is analysed based on the production and import/export of electricity. Previous research has found that as the amount VRE increases then the traditional flexible thermal plants full load hours are reduced, however, though there is a reduction in full load hours of these plants there is still a need for the electric capacity these plants provide [11], [12]. Here it is investigated if this is the case for the three chosen scenarios, as that can highlight what the market for flexible thermal plants is going forward. Non-flexible operating thermal plants, such as waste incineration and industrial CHP units, is not included in this analysis. The capacity of the flexible thermal plants and the transmission line capacity in each modelled scenario are shown in Table 1.

Table 1 – Flexible thermal electric capacity in each scenario

	2020	2035			2050		
[GW]	Ref. model	ST	GCA	IDA	ST	GCA	IDA
Flexible thermal plants	4.55	4.14	4.16	5.53	1.87	1.98	6.00
Transmission capacity	7.10	10.40	12.70	7.10	10.40	12.70	7.10

As shown in Table 1, where the ST and GCA scenarios have increased transmission line capacity and reduced flexible thermal plant capacity compared with the 2020 reference model, the IDA scenario does not increase transmission line capacity, however, it has an increased flexible thermal plant capacity.

When investigating the operation of an energy conversion technology, an often-used metric is the number of full load hours that the unit produces per year. Full load hours shows the energy production of the technology in relation to the installed capacity by showing the yearly energy production by how many hours it would take the unit to produce that amount of energy if only operating at full capacity. The number of full load hours in the three scenarios at three different electricity market price levels, being 16 EUR/MWh, 47 EUR/MWh and 77 EUR/MWh, can be seen in Table 2.

Table 2 - Full load hours for CHP and power plants (excl. mostly baseload operating plants) in the different scenarios at three different external electricity market price levels. Medium fuel price level

	2035			2050		
	ST	GCA	IDA	ST	GCA	IDA
16	142	151	31	6	5	265
47	1,066	2,099	2,352	1,342	1,195	1,252
77	2,924	4,308	5,488	2,649	1,921	3,033

As shown in Table 2, at comparable electricity market price levels the number of full load hours decreases in the 2050 scenarios compared to the 2035 scenarios, with only two exemptions, being the ST scenario at 47 EUR/MWh and IDA at 16 EUR/MWh. For the IDA scenario at 16 EUR/MWh the increase is due to a general higher electricity demand in 2050 compared with 2035. As the electricity transmission capacity is the same in IDA2035 and IDA2050, the flexible thermal plants are used more in cases with bottlenecks related to import of electricity. For the ST scenario at 47 EUR/MWh, it is due to the lower capacity of flexible thermal

plants compared with the 2035 scenario. For comparison, in the 2020 reference scenario, which has an electricity market price level of 34 EUR/MWh, the flexible thermal plants are operated at 2,645 full load hours. It is also clear that the IDA scenario generally has more full load hours for the flexible thermal plants, due to the lower transmission line capacity and higher electric efficiency of the flexible thermal plants, compared with the ST and GCA scenarios.

However, full load hours do not show how the units are operated throughout the year. To further illustrate the operation of the flexible thermal plants, duration curves for their hourly electricity production is produced. Figure 13 shows the duration curves for non-baseload CHP and power plants in 2035 for the three different scenarios at three electricity market price levels. The similar duration curve for the 2020 reference model is also shown for comparison purposes, which has an electricity market price level of 34 EUR/MWh.

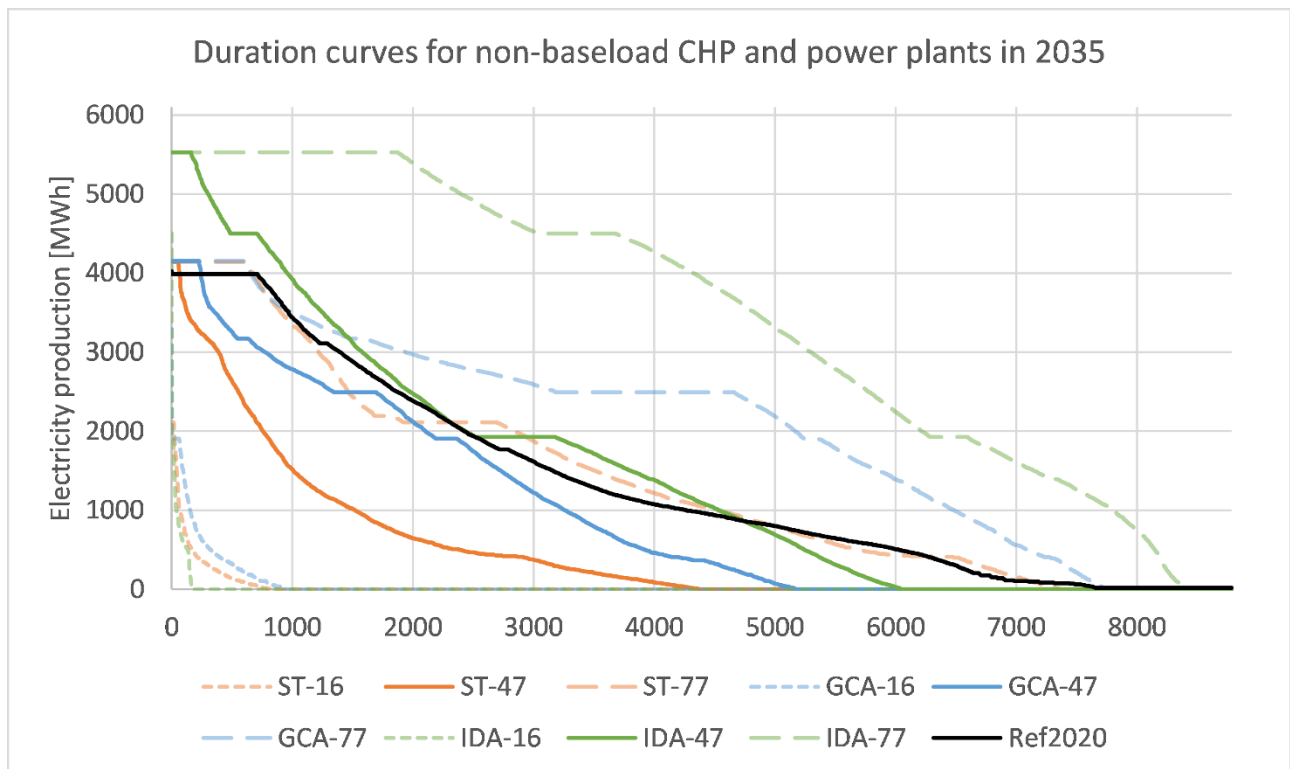


Figure 13 – Duration curves for the electricity production of CHP and power plants in 2035 at three different levels of external electricity market prices levels and the reference model for 2020. The fuel price level is medium. Mostly baseload operating plants, such as waste incineration, have been excluded.

As shown in Figure 13, the production of electricity is significantly dependent on the electricity market price level, as a high electricity market price encourages a higher electricity production. A low electricity market price reduces the electricity production substantially so that the flexible thermal plants are only in operation less than 1,000 hours per year, and at this low price level only in less than 20 hours per year the flexible thermals plants are operated at full load in all scenarios. However, at the 47 and 77 EUR/MWh price levels, some operation of the flexible thermal plants occurs in most of the year, regardless of scenario.

Going to 2050, Figure 14 shows the duration curves for non-baseload CHP and power plants in 2050 for the three different scenarios at three electricity market price levels.

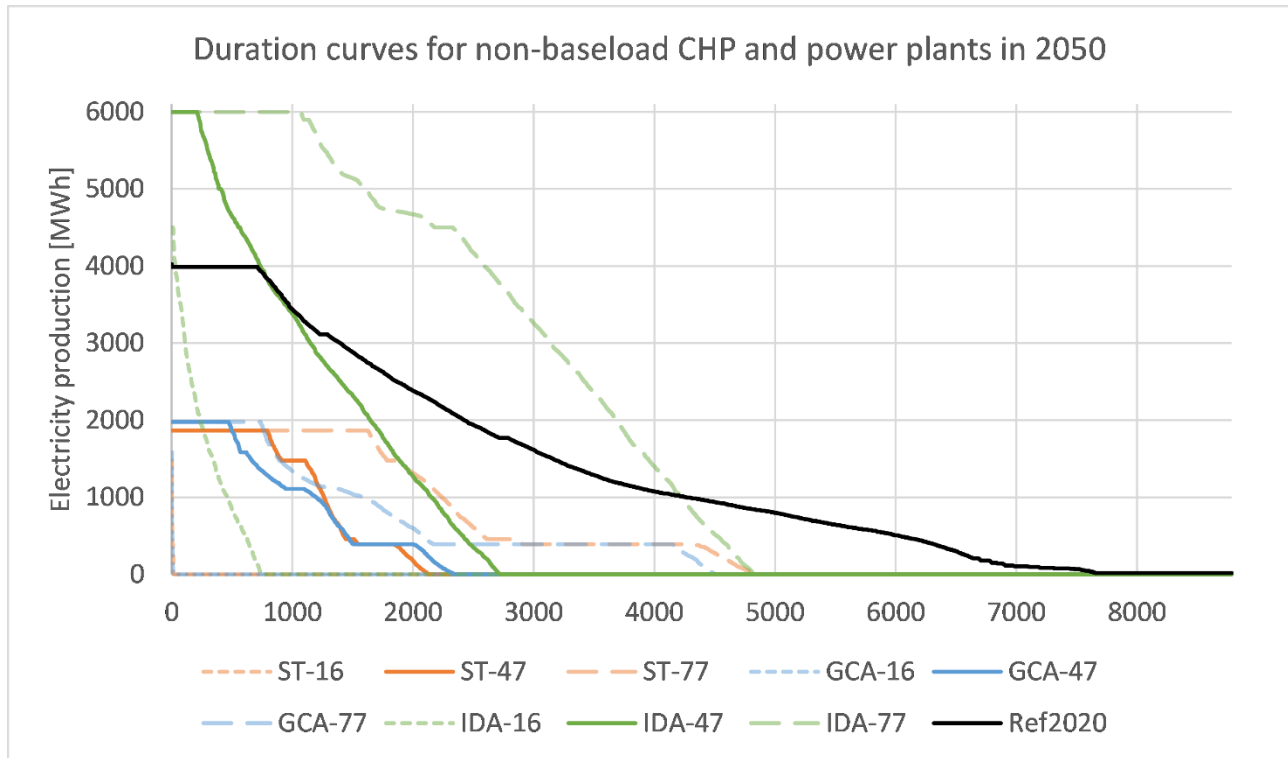


Figure 14 - Duration curves for the electricity production of CHP and power plants in 2050 at three different levels of external electricity market price levels and the reference model for 2020. The fuel price level is medium. Mostly baseload operating plants, such as waste incineration, have been excluded.

As shown in Figure 14, in all scenarios, the operation hours of flexible thermal plants are reduced in 2050 compared with 2035, as shown in Figure 13. In the IDA scenario, which has the highest capacity of flexible thermal plants, at the high electricity market price level, the total capacity is only operating at full load approximately 1,000 hours a year, down from 1,900 hours in 2035, and the amount of hours with any operation of these plants is reduced from 7,400 hours in 2035 to around 4,800 hours in 2050. However, the flexible thermal plants in the IDA scenario at the low electricity market price operate more in 2050 compared with 2035, due to the increased electricity demand without increased transmission line capacity, meaning that the flexible thermal plants operate more in order to maintain stability in the power system in 2050 compared with the 2035 scenario. In 2050 at the low electricity market price level, the flexible thermal plants in the ST and GCA scenarios are only operated around 15 hours per year with only a couple of hours at full load, which is due to the larger transmission line capacity that can facilitate the electricity demand with the import of electricity from surrounding areas.

The difference between Figure 13 and Figure 14 suggests that the value of flexible thermal plants for the energy system goes from the amount of electricity produced to be the flexible electric capacity that they offer to the system. This is also in line with some of the previous research findings.

Due to the importance of the transmission line capacity, it is relevant to investigate their utilisation further. The duration curves shown for utilisation of the transmission line capacity is only related to the transmission of electricity needed for the operation of the modelled Danish energy system. As such, the duration curves

do not include, e.g. transmission of electricity through the Danish energy system to be used in another country. Figure 15 shows the duration curves for import in 2035 with the same price levels as used in previous figures.

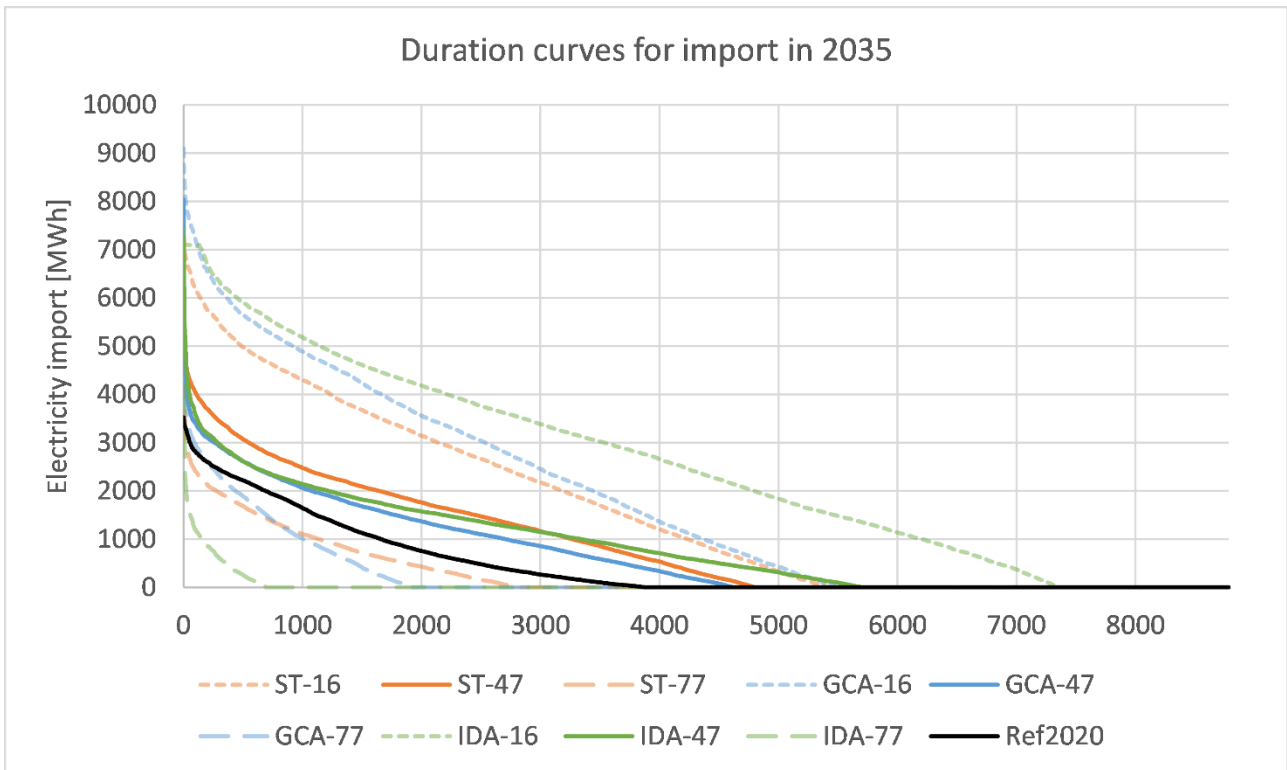


Figure 15 - Duration curves for the import of electricity in 2035 at three different levels of external electricity market price levels and the reference model for 2020. The fuel price level is medium.

As seen in Figure 15, the import of electricity in 2035 is affected by the cost of electricity, with a low electricity market price increasing the import of electricity. It is also clear that the total capacity of the transmission capacity installed in the ST and GCA scenarios is not fully utilised for import of electricity in any hour of the year, as 10.4 GW is installed in ST2035 and 12.7 GW is installed in GCA2035, as shown in Table 1. In the IDA scenario, the transmission line capacity is at most fully utilised in around 130 hours.

Going to 2050, Figure 16 shows the duration curves for import in 2050 with the same price levels as used in previous figures.

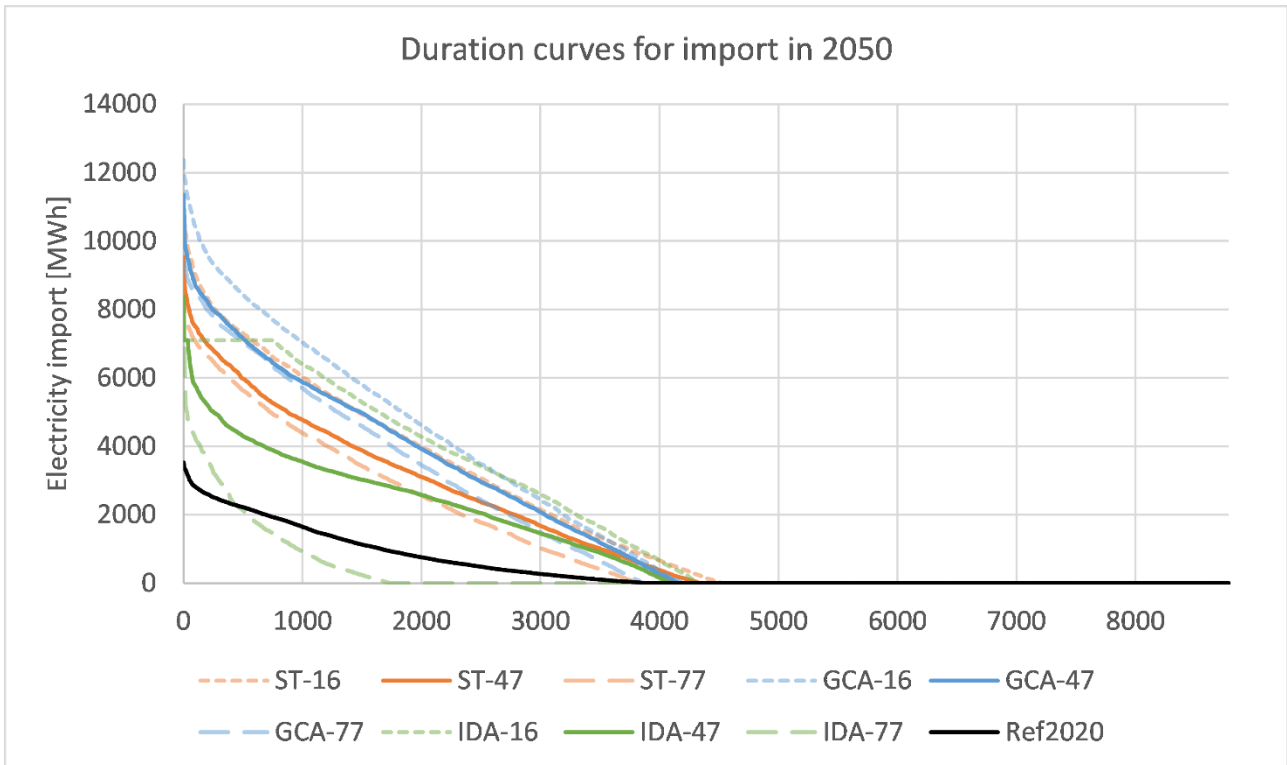


Figure 16 - Duration curves for the import of electricity in 2050 at three different levels of external electricity market price levels and the reference model for 2020. The fuel price level is medium.

As shown in Figure 16, in 2050, the max utilisation of the transmission line capacity for import of electricity is increased in all scenarios compared to the 2035 scenarios. However, the amount of hours without utilising the transmission line capacity at all for import is more similar in all scenarios where in most cases the transmission line capacity is utilised for import in about half of the year. The transmission line capacity is fully utilised for import in around 10 hours in the ST scenario, and only fully utilised in the GCA scenario in one hour. At the low electricity market price level in the IDA scenario, the transmission line capacity is fully utilised in around 750 hours.

Looking instead at the export utilisation, Figure 17 shows the duration curves for export of electricity in 2035 with the same price levels as used in previous figures.

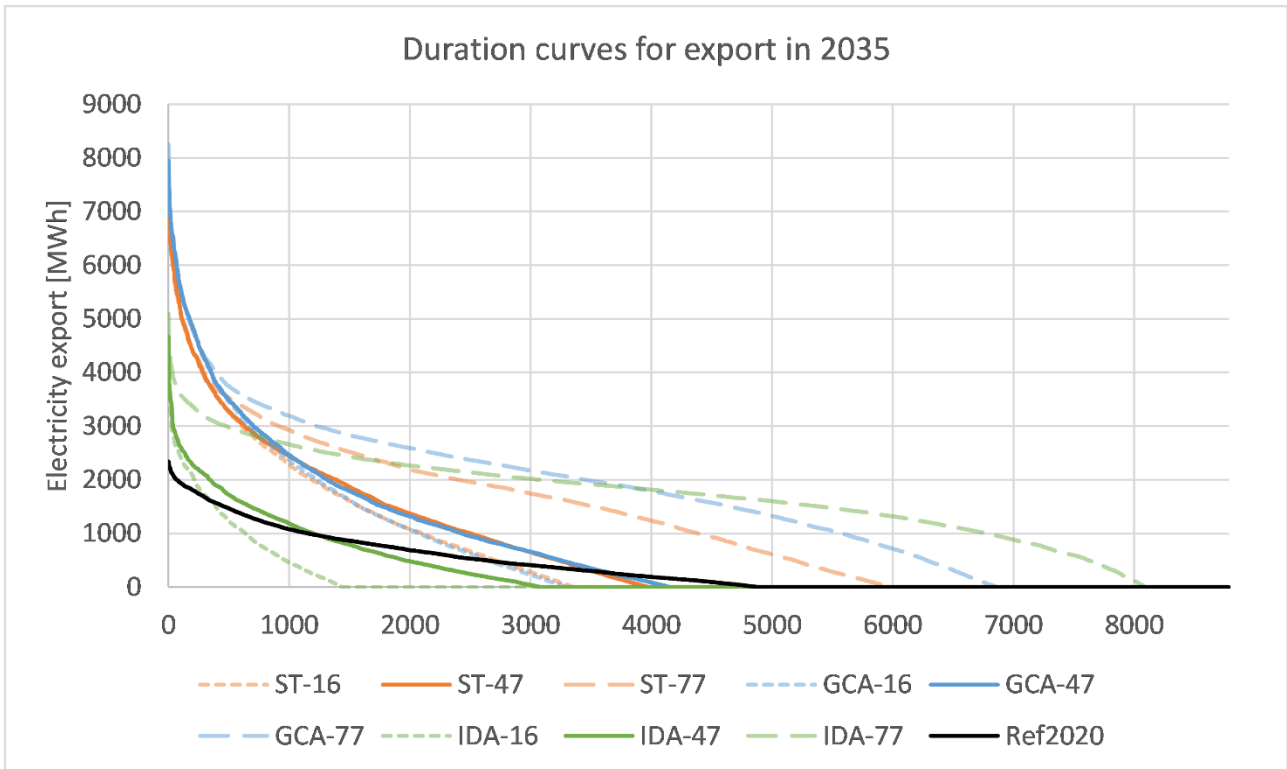


Figure 17 - Duration curves for the export of electricity in 2035 at three different levels of external electricity market price levels and the reference model for 2020. The fuel price level is medium.

As shown in Figure 17, the export of electricity in 2035 is affected by the cost of electricity, with a high electricity market price increasing the export of electricity. As with imports in 2035, the total transmission capacity installed in ST and GCA scenarios is not fully utilised in any hour of the year, as 10.4 GW is installed in ST2035 and 12.7 GW is installed in GCA2035. However, differently from the imports in 2035, looking at the export the transmission line capacity in the IDA scenario is also not fully utilised in any price scenario, with a transmission line capacity of 7.1 GW.

Figure 18 shows the duration curves for export in 2050 with the same price levels as used in previous figures.

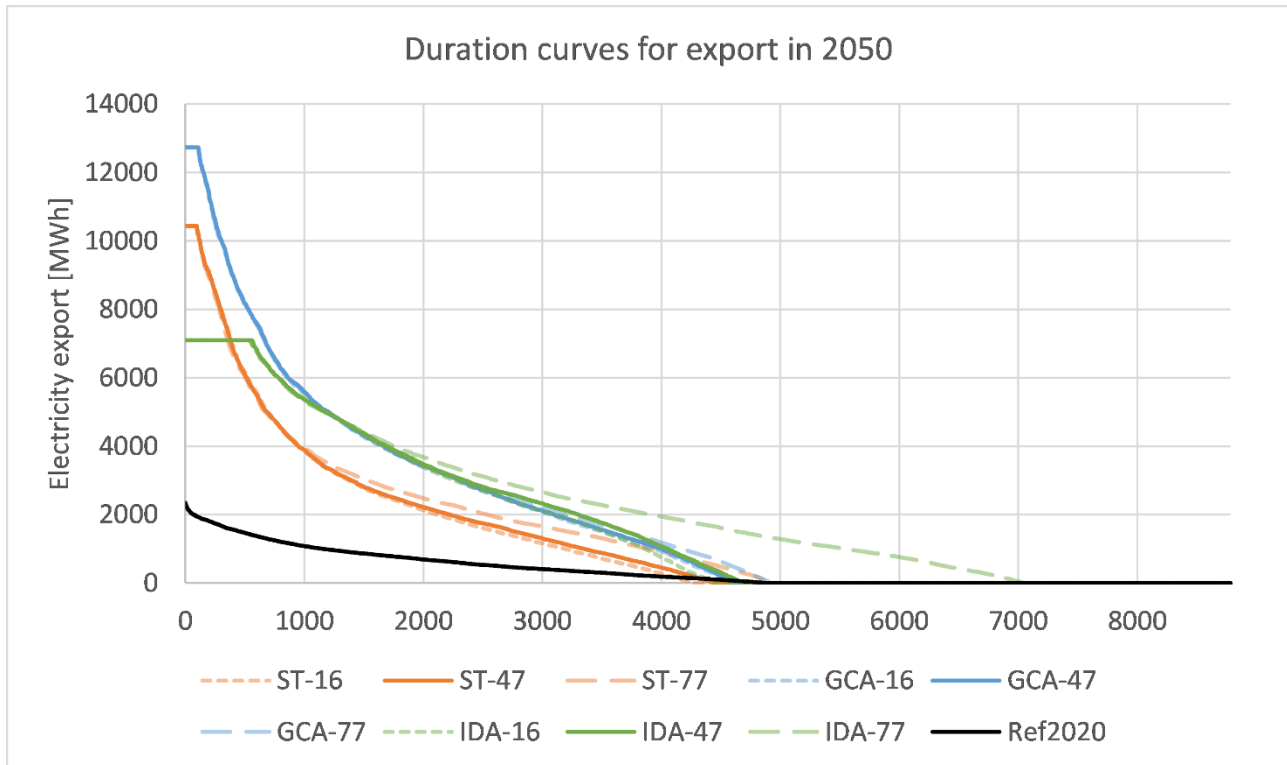


Figure 18 - Duration curves for the export of electricity in 2050 at three different levels of external electricity market price levels and the reference model for 2020. The fuel price level is medium.

As shown in Figure 18, the export of electricity in 2050 is less affected by the electricity market price level as the export in 2035, which is due to increased export of electricity by VRE in 2050. However, the export in the IDA scenario is more affected by the electricity market price level than the other scenarios, which is due to a larger installed flexible thermal plant capacity that is more efficient than those installed in the ST and GCA scenarios. Regardless of the electricity market price level, the transmission line capacity is fully utilised in about 90 hours in the ST scenario, 100 hours in the GCA scenarios and 540 hours in the IDA scenario.

Based on the import and export duration curves for electricity related to the modelled energy system, the ST and GCA scenarios capacity of transmission lines are not fully utilised in 2035. Some of the transmission line capacity might, however, have been included by Energinet to allow for the transition of electricity through the Danish energy system to other countries, or to allow for redundancies and backup in case of breakdowns of transmission lines or to connect to more countries in order to increase the possibility of utilising electric producing units in other countries for Danish electricity demands. In the 2050 ST and GCA scenarios, the transmission line capacity is, however, utilised fully in some hours, especially in relation to the export of electricity produced by VRE. The IDA scenario generally has a higher utilisation rate of its lower installed transmission line capacity, which also is utilised more in the 2050 version of the scenario than in the 2035 version.

5 Electrification

Increased electrification is essential in the transition towards the future renewable energy system, as evident from the diverse range of electrification measures and technologies included in all the scenarios investigated in this study. While there are differences across the GCA, ST, and IDA scenarios included in this analysis, some general tendencies on electrification are consistent throughout all scenarios. Examples of this include extensive use of electric HPs in both individual and DH areas, a transportation sector based predominantly on electricity and electrofuels, and electrolyzers for hydrogen production; electricity demands supplied mainly through VRE production.

Electrification of the energy system in general, and in particular the use of electric HPs, has been tackled extensively in existing research for both a European and a Danish context. Examples of this include a study on large-scale HPs in European DH from the Heat Roadmap Europe project [13], and similarly for Denmark a study on the socio-economic benefits of large-scale HPs in DH [14]. There is, however, still a need for research on electrification in other areas and sectors of the energy system.

In Denmark, the energy consumption of the industry sector accounts for approximately 20% of the final energy demand [15] while being largely dependent on fossil fuels. Decarbonisation of the industry sector is thus a pivotal challenge in the transition to renewable energy systems. However, despite comprising of a significant share of the energy demand, the industry sector is often only sparingly included and at times, entirely overlooked in studies on energy system transitions [16].

Decarbonisation of the industry sector faces some inherent challenges including costs, trade sensitivity, and long facility lifetimes, all contributing to slow diffusion of energy decarbonisation measures. Furthermore, the heterogeneity of the industry sector, i.e. caused by the differences in production facilities over the world and the variety of products produced, increases the complexity of decarbonisation [17].

Among the most well-established measures for industry-decarbonisation are energy efficiency improvements, fuel substitution, electrification, and energy cascading (i.e. the re-use of waste heat either within the industrial facility or outside for heating purposes) [17]. The analyses of this study mainly focuses on the potential for direct electrification of industry using electric HPs and electric boilers, and indirect electrification through fuel substitution, mainly in the form of a shift to hydrogen-based industrial processes.

Ensuring flexibility of the energy system is another critical step towards renewable energy systems; still, flexibility remains a somewhat vague concept, as flexibility in an energy system is not limited to a specific energy sector or technology, but can be provided in many different ways.

Flexibility is mentioned when comparing different energy production technologies and the extent to which production is dispatchable or variable, e.g. in discussions and comparisons of traditional power plants and wind turbines. Flexibility can also be improved through increasing the available storage capacity, e.g. heat storage, electricity, or gas storage so that that excess production can be stored and used later. Some energy demands may also be flexible in the sense that consumption can be shifted by a few hours, days, or even weeks, depending on the current renewable energy production and market prices. This could be the case for small-scale consumers such as households, where some of the heat and electricity demands could be shifted outside of peak hours. Likewise, demands for transport and electric vehicles may be able to be shifted to

hours with significant VRE production, and some energy-intensive industries may also be able to adjust their production. Finally, energy-intensive P2X processes, e.g. electrolysis, are likely essential flexibility options in the future, as large amounts of energy can be consumed when needed and the produced P2X products generally are storable.

In the scenario background report [18], Energinet outlines the importance of increased flexibility of the electricity demand in the future due to the many energy system benefits, e.g. to reduce peak loads. Energinet further argues that in the future, electricity demand flexibility should be combined with international transmission to provide grid balancing services. Similarly, in the IDA's Energy Vision 2050 report [1], the authors also emphasize the importance of system flexibility, both in the electricity demand and other sectors. Therefore, while the general stance on the importance of flexibility is similar for the scenarios developed by Energinet and IDA, the scenarios may respond very differently to flexibility mechanisms due to system differences.

Another way of adding flexibility to the energy system could be through electricity storage, which may have several desirable interactions within future renewable energy systems, e.g. for balancing of VRE, or for providing ancillary services and other means of grid balancing due to the fast response times of most electricity storage technologies. For this study, electricity storage technologies are defined as technologies for which electricity is both the input and output, regardless of the medium used to store the energy. This broad definition captures a broad range of technologies such as:

- Pumped hydro
- Compressed air
- Flywheel
- Hydrogen (or other power-to-X)
- Lithium-ion Batteries
- Vanadium-redox flow batteries
- High-temperature rock bed storage

It is not within the scope of this analysis to quantify each of the above technologies; instead, the fundamental interactions of electricity storage technologies and renewable energy systems are the primary targets.

5.1 Previous research

The following section presents an overview of previous research on industrial electrification, electricity demand flexibility, and electricity storage, prioritizing a Danish context to derive a specific analytical scope of the subsequent analyses.

5.1.1 Industry electrification

Like previously mentioned, electrification of the energy system has been central in research on renewable energy systems. This has, however, often been in the context of residential- and DH or the transport sector, leaving the role of electrification and HPs for the industry sector not as established.

In a study on the decarbonisation of the European industrial sector, Lechtenböhmer et al. [19] conduct a what-if analysis on the implication of complete electrification of the European industrial sector. The study

suggests that electrification is technically possible, but because of the resulting immense increase in electricity demand, such a transition could have significant implications for the energy- and electricity system. Thus, the authors conclude that continued research is needed on the co-evolution and integration of 100% renewable electricity systems and industry electrification. The Danish energy system, with its current and expectedly future high penetration of VRE, could be a suitable candidate for such electrification scenarios.

Kosmadakis [20] estimate the potential for high-temperature HPs in European industry on both a country level and a combined EU28 through a mapping of the excess heat potential, finding a potential for covering 1.5% of the total industrial heat demand in Europe. However, this is solely the potential for high-temperature HPs (temperatures above 150°C), where the required waste heat can be recovered from the industry sector. Therefore, the total potential for HPs in the industry may prove to be much larger than estimated by Kosmadakis, if the scope is broadened to include both low- and high-temperature HPs, and more readily available heat sources such as, e.g. ambient air. Applying a similar methodology to Kosmadakis, Bühler et al. [21] investigate the potential of HPs for electrification of the Danish industry, emphasising the estimation of excess heat for HPs to supply process heat. Neither Kosmadakis nor Bühler et al. applies these findings in an energy systems perspective with regards to how the increased electrification impacts the remaining energy system from HPs; something which may be relevant to explore further.

Wiese and Baldini [22] develop a model for energy system analysis of Danish industry sector using the Balmorel tool. The industry sector is clustered into five different categories, each with different temporal distributions based on differences in demands and processes. The Balmorel model developed for the study enables the investigation of a disaggregated sector, while still considering its connection to the electricity and heat sectors. The objective function of the model is total system cost, enabling the model to optimise changes to the industry sector such as the implementation of energy savings measures, conversion of fuels, e.g. through the installation of HPs, thus providing some insights on the applicability of such measures in a Danish context.

Bühler et al. [23] estimate the potential for electrification of the Danish industry sector based on the distribution of heat demands amongst industries and processes and temperature levels. The study finds that most of the Danish industry demand can be electrified, reducing final energy demand by one third, largely a result of increased HP integration. The economically feasible potential is, however, considerably lower than the technically feasible potential. The study does not apply the findings for energy system modelling or quantify how electrification of the industry sector impacts, e.g. the heat and electricity sector.

In a study by Ridjan et al. [24], the role of electrolysers for electrification of the energy system and grid balancing is investigated for Denmark. The primary contribution of electrolysers is found to be the production of fuel for the transport sector, while the integration of renewable energy and grid balancing should merely be considered as additional benefits. The study did not consider scenarios with large-scale conversion to hydrogen-based industrial processes, and thus this may instead be potential a research area to explore further.

5.1.2 Electricity demand flexibility

In a previous assessment of flexible demand in a Danish energy system, Kwon and Østergaard [25] estimated the potential for flexible demand in the residential, commercial and industrial sectors. To determine the potential for flexible demand, the authors employ a technical approach where processes for residential, commercial, and industrial sectors are assessed according to the controllability and the storability of the processes. The resulting potential flexible demand for the three sectors within a day is limited to 7% of the total electricity demand. To determine the system impacts a 2050 scenario by the Danish Climate Commission is modelled in EnergyPLAN, and the value of the determined flexibility potential is assessed; primarily in terms of consequences to the international exchange of electricity and operation of condensing power plants. Kwon and Østergaard conclude that the determined potential demand flexibility does not significantly influence the international exchange or power plant operation in the tested Danish 2050 system, and an unrealistically high flexible demand would be needed to change this conclusion. However, the authors did not consider the system impacts for other system parameters, and the results are highly specific to the specific energy system scenario modelled.

In a review of research on flexible demands, Kondziella and Bruckner [26] categorize different approaches applied in existing studies of flexible demand. The authors find that studies on flexibility options exist for both the supply-side and demand-side of the energy system and categorized according to seven general categories:

1. Highly flexible power plants that could cope with increasing ramping requirements
2. Energy storage in large-scale applications
3. Curtailment of renewable surplus generation
4. Demand-side Management (DSM)
5. Grid extension
6. Virtual power plants
7. Linkage of energy markets like those satisfying the electricity and heat demand

Kondziella and Bruckner (p. 11) [26]

As evident from the different categories of flexibility options and a diverse range of studies, the authors find that an extensive range of current and future technologies and measures are available for providing system flexibility. This will be needed, as the increasing VRE share necessitates higher levels of flexibility. Kondziella and Bruckner conclude that potential for flexible technologies exists, but existing research primarily considers the technological potential for flexibility, with only a few studies aimed at quantifying the economic potential and market mechanisms required.

Comparing smart grid and smart energy system approaches, Lund [5] outline how such analytical and methodological approaches influences results and technology prioritization. This is tested by analysing scenarios representing a smart grid and smart energy systems approach, respectively. For the smart grid approach, this is exemplified through individual electric heating and individual electric HP scenarios, while smart energy systems approach is represented through an electric HP and DH scenario. The results of the study emphasise how an analysis focusing on the electricity sector will provide vastly different results compared to a smart energy system with more integrated energy sectors.

Mortensen et al. [27] investigate the role of electrification and hydrogen in ensuring a sustainable consumption of biomass in future renewable energy systems, and in doing so also discuss the role of flexibility extensively. The authors review 16 different Danish scenarios for 100% renewable energy systems to uncover general design principles, with varying levels of bioenergy consumption, electrification, and electrofuel production. The outcome is nine different design principles with very different system typologies and levels of biomass consumption. The identified systems have different strategies for coping with the need for flexibility; e.g. a system relying on VRE such as wind and solar while having limited system integration may require a massive overcapacity to meet demands during low production periods. On the contrary, a highly integrated system with flexible demands due to integration of hydrogen, electric vehicles, HPs, and electrolyzers can more efficiently utilise VRE production peaks and shift consumption away from periods with low VRE production.

In an investigation of future energy markets, Sorknæs et al. [28] argue that in the transition to renewable and smart energy systems, the electricity market cannot be considered only as an isolated market, but must be viewed in correlation to other markets such as heating, renewable gas, and liquid fuels. As energy systems transition towards high shares of RES, a need for re-designing markets will arise. Presently this is apparent for the electricity market where increasing VRE production causes electricity price decreases, but Sorknæs et al. expect to encounter a similar trend in the renewable gas and liquid fuel markets, and hence argue for a need to introduce Smart Energy Markets; a conceptual understanding of interconnected energy markets. This idea underlines the future need for considering not only technical limitations for system flexibility but also the need for appropriate markets structures and market mechanisms supporting flexibility enhancing measures.

5.1.3 Electricity storage

While extensive research is conducted on electricity storage technologies in general, e.g. in the form of cost comparisons [29] or technical assessments [30], [31], only limited research is done on the role and application of electricity storage in a Danish renewable energy system. Therefore, the following overview of previous research extends beyond the Danish system and includes research conducted on electricity storage also in an international context.

In an investigation of the technical and economic potential of distributed energy storage, Sveinbjörnsson [32] analyse the interaction of Germany's energy system and electrical energy storage technologies such as li-ion batteries, power-to-gas-to-power (hydrogen) and vanadium-redox flow batteries. The study finds that electrical energy storage technologies are technically beneficial to the energy system but are not economically feasible due to high technology investment costs and thus increased total system costs. This may, however, change depending on how flexibility mechanisms and power-to-heat technologies are incorporated, and there may therefore be some value to modelling electrical energy storage technologies in other energy systems.

Lund et al. [33] report on the role of different storage types in renewable and smart energy systems. The authors argue that electricity storage, in general, is inferior to alternatives such as thermal, gas or liquid fuel storage due to a combination of investment cost and cycle efficiency. The study concludes that focusing solely on the electricity sector will lead to sub-optimal solutions such as an over-emphasis on expensive electricity storage solutions, flexible electricity demands, and international transmission lines. Instead, emphasising

sector integration enables the use of cheaper alternatives such as thermal storage and HPs for large-scale integration of RES. Mathiesen et al. [34] present similar conclusions in the study on smart energy system solutions, drawing upon quantitative results from the CEESA project in which extensive energy system modelling is conducted for Denmark, including future renewable energy scenarios. However, as of 2020, the CEESA model is outdated, and further investigations based on up-to-date energy system models may provide valuable insights.

In a study specifically on the role of compressed air storage in the Danish energy system by Salgi and Lund [35] find that it is technically and economically unfeasible to eliminate excess electricity production through compressed air storage alone. The study modelled the Danish energy system using the EnergyPLAN model and tested increasing capacities of both storage and wind power installation and how the excess electricity production and operation of CHP plants and power plants changed accordingly.

Researchers are continuously looking for alternative technologies for energy storage, and a potential option for the future is high-temperature energy storage, where heat is used as a storage medium, e.g. stored in the form of rocks at high temperature (600°C), and used to produce high-pressure steam to expand in a turbine. In a Danish pilot project, a small-scale high-temperature rock bed storage solution has been developed and tested [36], [37] and preliminary numbers on heat losses, charging and discharging efficiencies have been obtained. On a conceptual level, the rock bed storage solution should be relevant for storing energy for a few days and up to a few weeks and utilise fluctuations in VRE production to charge during periods of low electricity prices. Rock bed storages could prove to be relevant in future renewable energy systems as a lower investment cost compared to other electricity storage technologies would be a significant advantage. While rock bed storage is in an early technological development stage, it is relevant to include this technology in energy system scenarios and thereby investigate how it may interact with the surrounding energy system.

In the report “Roadmap for electrification in Denmark” [38] EA Energianalyse investigates the potential for increased electrification of the Danish energy demand based primarily on energy system modelling in Balmorel. The purpose of the study is quantifying what is needed to reach the goal 2030 70% emission reduction and 2050 100% emission reduction targets. The assessment includes the electricity, heating (individual and DH), transport and industry sectors, thus enabling analysis of electrification as a sector coupling mechanisms. Scenarios differ in terms of how ambitious investments in electrification are implemented, and the level of flexibility incorporated. Flexibility is incorporated as a metric of how many hours a particular demand can be shifted in time, ranging from zero to six hours. For short term storage battery technologies are assumed to be installed, with installed capacity ranging from below 0.5 GWh to more than 2.5 GWh depending on the scenario. This is mainly based on the extent of additional flexibility mechanisms incorporated into the system, as these are assumed to lower the needed battery capacity. However, the study does not go into technologies for grid-scale electricity storage.

5.2 Analyses

This chapter investigates the role of electrification in three areas of the energy system:

- Industry electrification
- Electricity demand flexibility
- Grid-scale electricity storage

This investigation aims to determine the consequences of varying the electrification rate and electrification measures in the GCA, ST, and IDA energy system scenarios, to quantify the role of electrification in future renewable energy systems.

5.2.1 Industry electrification

Both the scenarios by Energinet and by IDA are based on the Danish Energy Agency’s Energy balance model, though from different years. As different versions of the Danish Energy Agency’s Energy balance model is used, differences occur in the projection of future demands towards 2035 and 2050, with regards to the industry sector boundary definition. Furthermore, there are some differences in modelling of process heat, which in Energinet’s scenarios is separated into more sub-categories based on temperature level than in the IDA scenario. Thus, the energy consumption of the industry sector in the Energinet scenarios cannot directly be compared to the consumption of the IDA scenario. Figure 19 presents the energy demand for process heating in the different scenarios, but as mentioned some reservations regarding the demand has to be included as the boundary definitions are not entirely consistent across the Energinet and IDA scenarios.

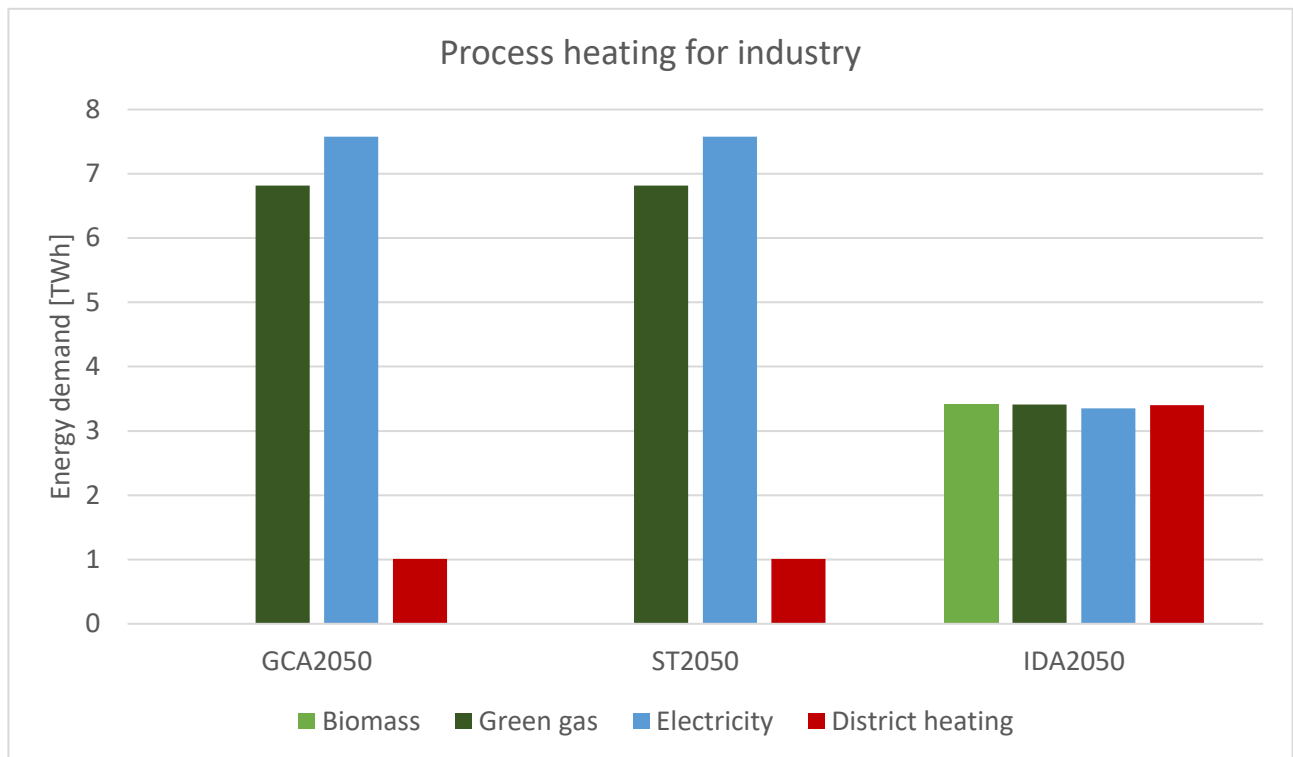


Figure 19 - Energy demands for process heating in analysed scenarios.

There are no differences in energy demand for the GCA and ST2050 scenarios; both rely primarily on electrical HPs and renewable gas for process heat demands. Eventhough there are no differences specifically within the industry sector in the GCA2050 and ST2050 scenarios, it is still relevant to include both in the following analysis. This is due to the energy system differences outside the industry sector, where differences in energy demands, supply technologies, or available storage technologies and capacities may cause the energy system to respond very differently to changes to the industry sector.

In previous research, the potential for direct electrification of the industry through HPs and electric boilers, and to a lesser extent indirect electrification through hydrogen processes have already been assessed for both a European and Danish context. However, these studies mostly consider the industry sector as an isolated entity, and rarely investigate changes in a broader energy system perspective. This study, however, quantifies systemic impacts of different pathways for transitioning the industry sector in the context of different scenarios for the Danish energy system, focusing on the consequences of 1) complete electrification of the industry sector, and 2) a shift to hydrogen-based processes.

In the Energinet scenarios, direct electrification primarily through HPs is expected to be the primary energy source in all scenarios, supplemented with renewable gas. The specific distribution of HPs and renewable gas is debatable, and it may be relevant to investigate the consequences of varying this electrification rate. The IDA scenario differs from this, putting a greater emphasis on direct electrification without HPs, resulting in lower efficiency, but also has a more balanced distribution of fuel sources. Biomass is used directly (e.g. in boilers) in the IDA scenario, without being converted to gas first like in the scenarios by Energinet, and it is relevant to investigate if it would be beneficial to shift this demand to electricity or hydrogen-based processes.

5.2.1.1 Direct industry electrification

The following analyses investigate the challenges of industry electrification, outlining the effects of both an increased and decreased electrification rate, taking into account the temperature levels of the process heat demand and utilization of HPs in the baseline scenarios.

In the Energinet scenarios, two different methodologies are tested for shifting demands from renewable gas to electricity (and vice versa); a simple and a more complex method. In the Energinet simple approach, demands are simply shifted from being an industrial renewable gas demand to an electricity demand considering a conversion efficiency of 80% for gas-based processes and 100% for electricity-based processes. The “low” efficiency of 100% for electricity is chosen since this analysis only concerns high-temperature processes above 150°C, equal to 35% of the total demand. The maximum potential available for shifting from electricity to gas-based processes is equal to the energy demand currently supplied by electrical HPs with a coefficient of performance (COP) of 1 (100% efficiency). This is chosen as these “low efficiency” high-temperature processes would be the most obvious potential for shifting to gas-based processes. This simple approach does not consider boundaries for available biomass potential; it is simply assumed that there is sufficient biomass available for such a technological shift. The more complex methodology assumes that the current biogas production and synthetic gas production from hydrogenation are at the maximum potential and cannot be increased further. Hence, any increase in renewable gas consumption is supplied through increased production at the biomass gasification plant. If the industrial renewable gas consumption is decreased because of increased electrification, the biomass input for the biogas production and hydrogenation is reduced concurrently.

In the IDA scenario, the solid biomass energy demand is shifted to electricity-based processes assuming an efficiency gain of 20%, as it is also assumed for the Energinet scenarios described in the previous paragraph.

The change in offshore wind power capacity with varying levels of electrification can be seen in Figure 20.

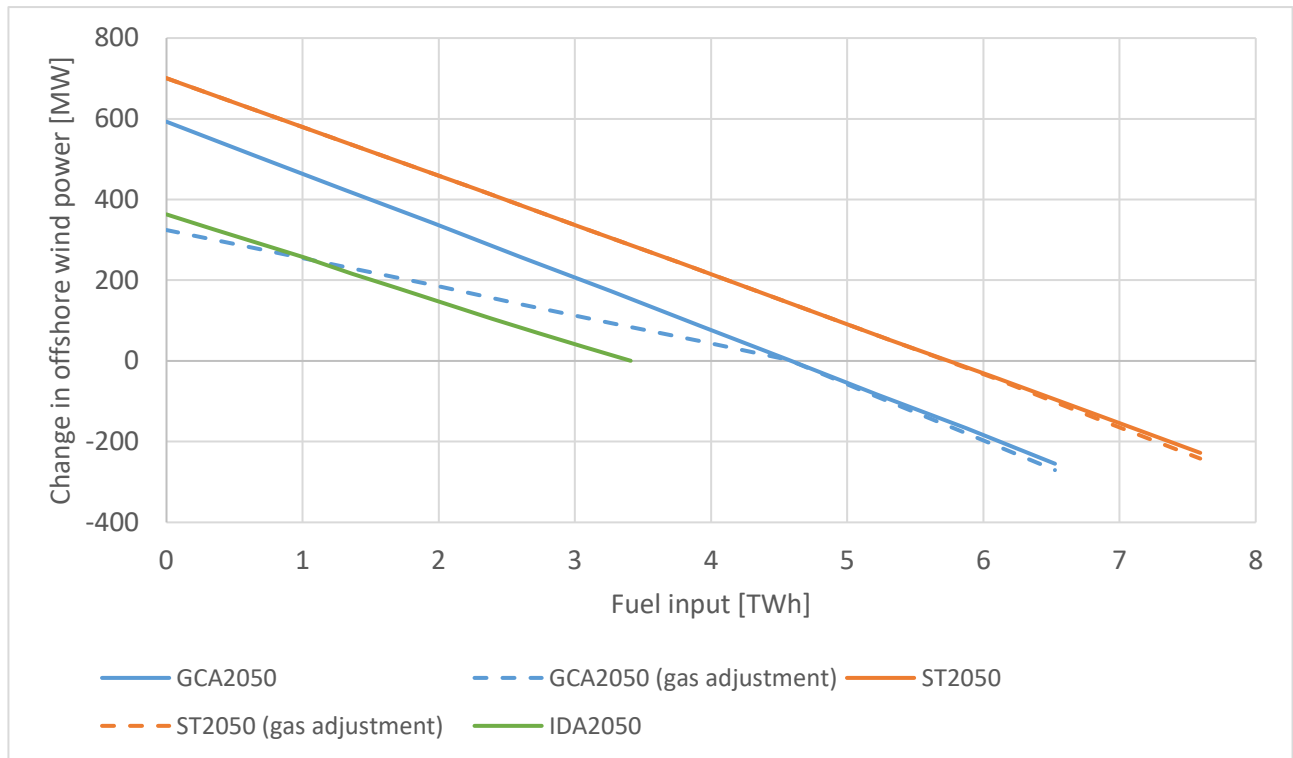


Figure 20 - The change in offshore wind power capacity made in each scenario at different levels of biomass/biogas fuel input for high-temperature processes in the industry.

For all scenarios, the results show a recurring trend where an increased level of electrification (fuel input decreasing towards zero) means that a larger offshore wind power capacity can be installed without causing additional excess electricity production. This indicates that continued electrification can contribute to increased integration of VRE. For the IDA scenario, it can be seen that the maximum tested fuel input is significantly less than in the Energinet scenarios. This is because a complete shift of the biomass demand to electricity occurs earlier in the IDA scenario as the industrial energy demand is also supplied by DH and renewable gas, which for this analysis were not changed.

Another immediate observation from Figure 20 is the differences in how much the offshore wind capacity can be increased at total electrification (zero fuel input). There are several reasons for this difference in maximum offshore wind capacity, with the most influential factor likely being the already existing installed capacity. In Figure 20, it can be seen that the highest potential capacity can be installed in the ST2050 scenario, which also has the smallest offshore wind capacity installed already. The GCA2050 and IDA2050 scenarios have approximately 4 GW and 6 GW more offshore wind power capacity installed respectively, which to some extent limits further expansion. Furthermore, the Energinet reference scenarios ST2050 and GCA2050 both have an electricity demand that is 15 TWh higher than the IDA2050 scenarios, which also impacts the system interactions and resulting offshore wind power potential.

Finally, a quite significant difference can be observed when comparing the GCA2050 (gas adjustment) to the GCA2050 without gas adjustment – a difference that does not occur for the ST2050 scenarios. This is due to the differences regarding electrofuel production in GCA2050 and ST2050 scenarios, and the previously described methodological approach for this analysis. The GCA2050 scenario has an electrofuel production from

electrolysers and biogas hydrogenation that is significantly larger than in the ST2050. As the industrial renewable gas demand is shifted to electricity, the biogas production (and production of electrofuels from biogas hydrogenation) is decreased. Thus, the increased electricity demand from industry is partly offset by a reduced electricity consumption during electrofuel production, resulting in a lower maximum offshore wind power potential at complete electrification for the GCA2050 (gas adjustment) scenario.

Figure 21 shows how the biomass consumption of the entire energy system is impacted by the changes to the industry electrification rate. The biomass consumption shown includes both the biomass directly consumed in the industry sector, but also changes to biomass consumption in other parts of the energy system.

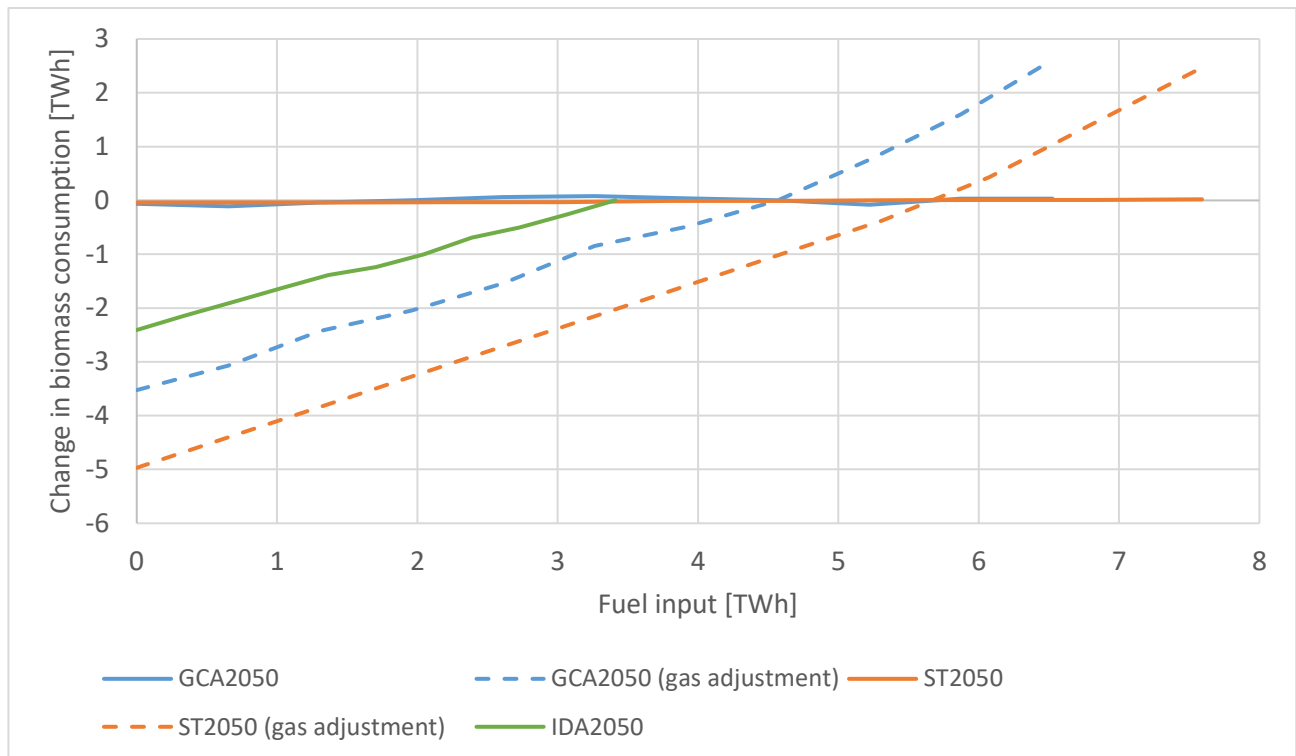


Figure 21 - The change in biomass consumption for each scenario at different levels of biomass/biogas fuel input.

One of the most apparent differences across the scenarios is how the biomass consumption for the GCA2050 and ST2050 scenarios is not significantly impacted. This is because of the methodological approach applied and specifically, the adjustment of biogas production relative to industry renewable gas consumption. In the GCA2050 and ST2050 scenarios without gas adjustment, the supply side is not changed. Therefore, the total biomass consumption of the system is not impacted by shifting fuels in the industry sector, as the same amount of biogas is being produced within the system. However, the export of biogas increases as the electrification rate increases because the biogas production is unchanged, as seen in Figure 22.

Electrification

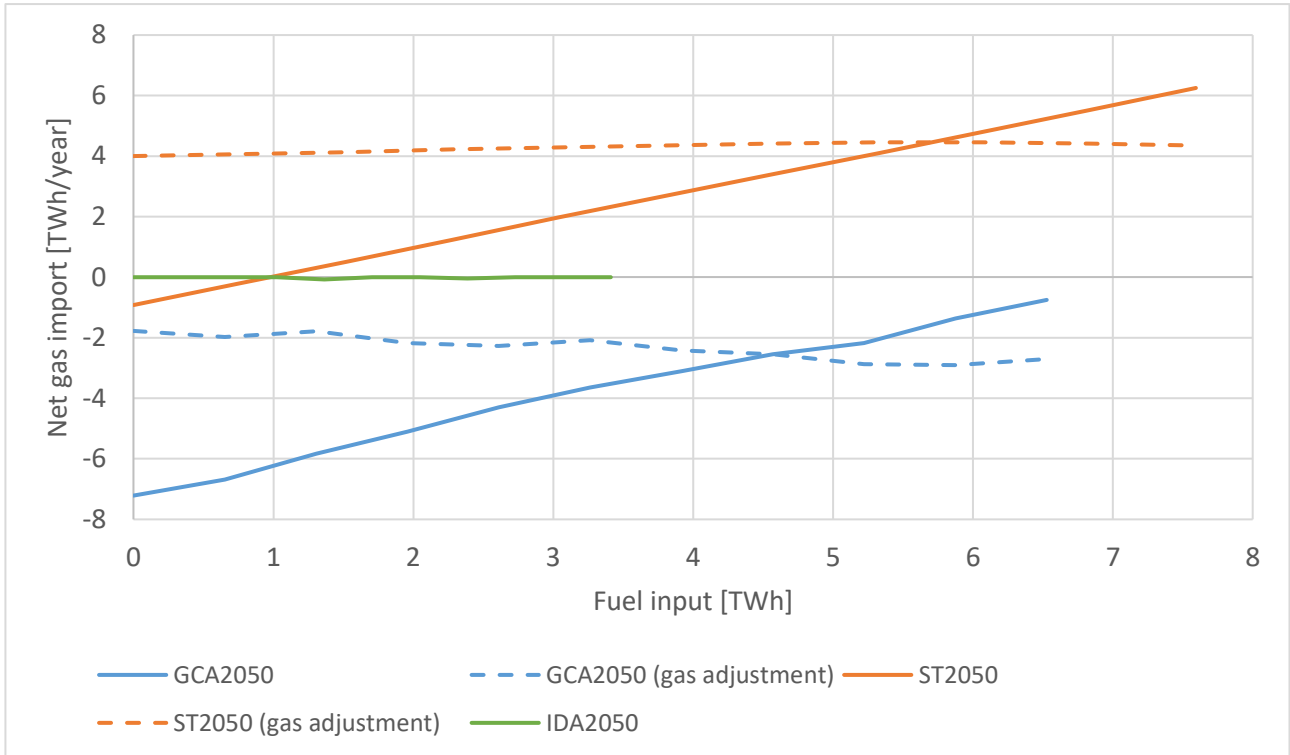


Figure 22 - Net gas exchange for each scenario at different levels of biomass/biogas fuel input. Negative values mean that a net gas export occurs in the scenario.

In Figure 23, the changes to the energy system costs for the different scenarios can be seen. From the variance in results across the different scenarios, it can be seen that the change in system cost as a result of electrification is heavily dependent on what scenario is analysed.

Electrification

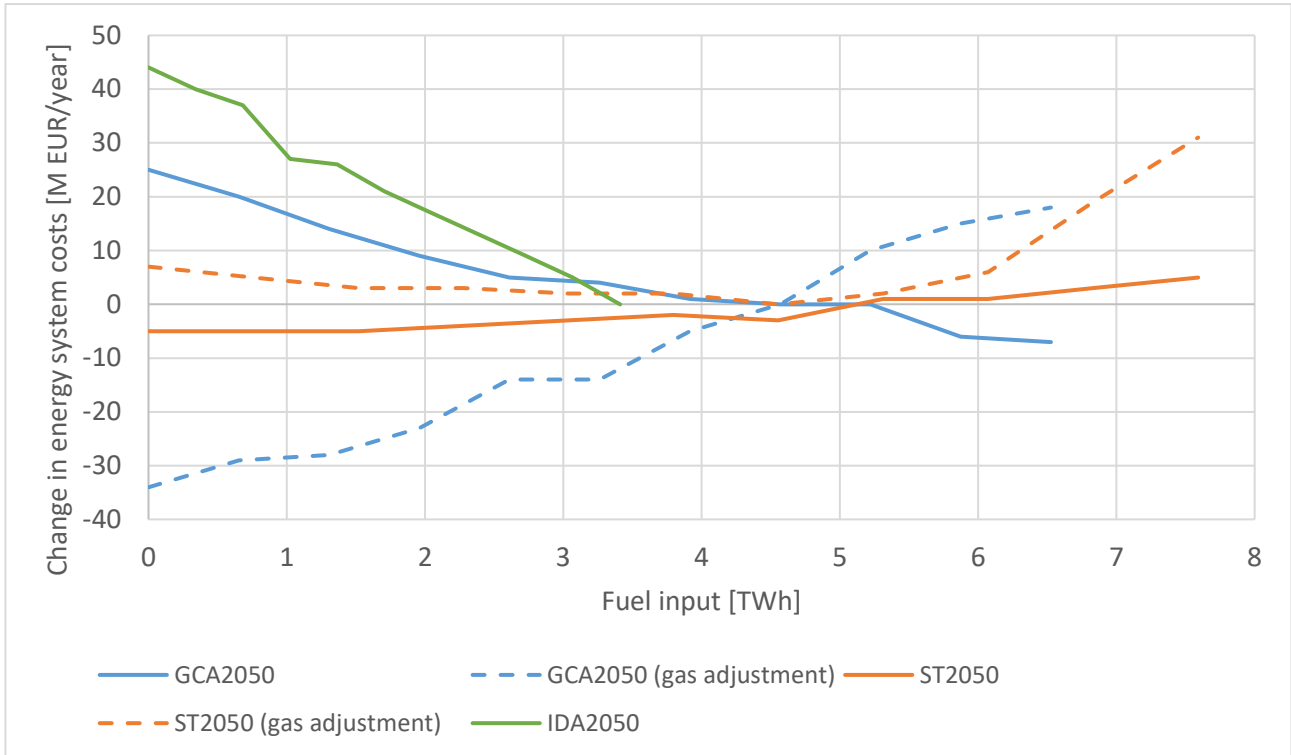


Figure 23 - The change in energy system costs for each scenario at different levels of biomass/biogas fuel input.

For all scenarios the change in offshore wind power capacity is an important deciding factor for the change in energy system costs; a large increase in offshore wind power capacity needs to be accompanied by correspondingly larger savings elsewhere in the system. Thus, the results on installed offshore wind power capacity from Figure 20 has an important influence on the energy system cost results in Figure 23. This is illustrated in Figure 24, where the investment cost allocated to wind power has been excluded.

Electrification

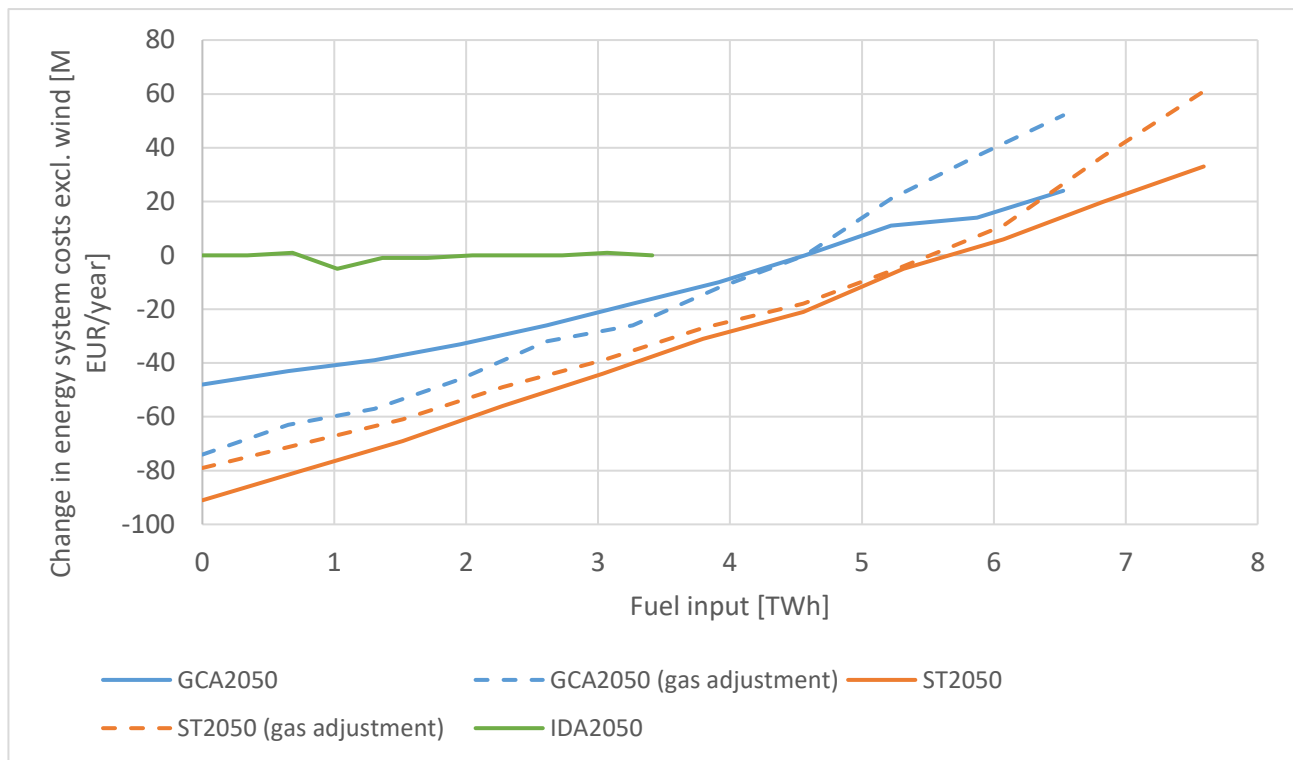


Figure 24 - The change in energy system cost, excluding the investment cost for wind power for each scenario at different levels of biomass/biogas fuel input.

Common for all Energinet scenarios is that the installed capacity for both large power plants and small CHP plants is smaller than in the IDA scenario, making international electricity exchange more prevalent. This causes the ST and GCA scenarios to increase the import of electricity more as the industry electrification rate increases. Further differences can be found in the gas sector, where for the IDA scenario the yearly import and export of gas are balanced, while for the Energinet scenarios, the Danish system can fluctuate between being a net importer to being a net exporter of gas (Figure 22), and the industry electrification rate can shift this balance.

The GCA2050 scenario shows an increase in energy system cost in Figure 23, but this is mainly due to large increases in the installed wind power capacity, and if this investment is excluded the increased electrification rate results in a lower total cost for the system (Figure 24). Because of the applied simple methodology in the GCA2050 scenario, gas production is not changed as the industry is electrified. Because of reduced renewable gas demand in the industry sector, the system can, to a larger extent, export the produced gas, resulting in an income to the system. However, as the production volume is unchanged, the production capacity is also unchanged, and the income from gas export cannot offset the increased costs of offshore wind power and electricity import. On the contrary, the GCA2050 (gas adjustment) scenario allows for a reduced biogas production along with a reduced installed capacity of the biogas and biomass gasification plants. This results in the energy system cost being reduced as the electrification rate increases. Therefore, the results for the GCA2050 and GCA2050 (gas adjustment) scenarios trend in opposite directions.

The energy system cost for the ST2050 scenario seen in Figure 23 does not drastically change because the scenario relies heavily on import of gas which can be reduced with increased electrification. However, this increases the investment in offshore wind and increases import of electricity, thus effectively offsetting each

other. The results for ST2050 and ST2050 (gas adjustment) are not very different to each other because compared to the GCA2050 scenario, the production of renewable gas from biomass hydrogenation is much reduced, and therefore the difference in methodology for gas adjustment does not matter as much. A change in the trend occurs for the ST2050 (gas adjustment) scenario in Figure 23 after a fuel input of approximately 6 TWh because this is where the maximum capacity for the biogas plant is reached and further increases in biogas consumption will need to be supplied by an increase in biomass gasification output.

For the IDA2050 scenario, a trend of increasing system cost with increasing electrification rate can be observed in Figure 23. This is because fuel savings for biomass cannot be offset by the increased investment in wind power and a slight increase in electricity import, resulting in the increasing cost with high electrification rates. The direct use of biomass in the IDA reference scenario is also a cheaper option than the renewable gas being used in the Energinet scenarios, which is part of the reason as to why there is little to no economic incentive for shifting to electricity in the IDA scenario. If the investment cost, which correlates to the increased wind power capacity is not included in the system cost, there is no real difference in the energy system cost, as seen in Figure 24.

5.2.1.2 *Industry hydrogen alternative*

The following analyses investigate the potential for indirect electrification of high-temperature processes in the industry through the use of hydrogen. Hydrogen is already an established fuel for the industry sector in Europe, primarily for the chemicals sector, refineries, and metal processing [19]. However, as the technology matures and prices decrease, new use cases for hydrogen-based processes in industry are likely to arise, e.g. for heat production through boilers or CHP [39]. There are therefore ample opportunities for shifting industrial processes, and in particular high-temperature processes, to hydrogen-based processes in the future. This analysis do not delve into the specific processes and technologies required at a plant level, this is already done in other studies [40]–[42], but instead focuses on the energy system interactions and economic consequences of a fuel switch to hydrogen.

Similarly to the modelling conducted for the direct industry electrification analyses, the methodology applied differs slightly for the Energinet scenarios compared to the IDA scenario. In the Energinet scenarios, a simple and complex method is again applied for fuel shifting. The simple method does not consider the gas supply side, but simply shifts existing renewable gas (and at later stages electricity) demand to a hydrogen demand considering conversion efficiency and electrolyser efficiency. The complex method, on the other hand, concurrent with the fuel shift to hydrogen, reduces production at the biogas and biogas hydrogenation plants. The IDA scenario is again slightly different in the sense that the gas production by default is adjusted to ensure yearly net import of zero. Thus reductions in the biomass demand will also be reflected in the supply side like the principle described for the complex method.

It is assumed that the transition to hydrogen-based processes will result in increased flexibility benefits because of the potential for storing hydrogen. For this study, it is assumed that the hydrogen demand is flexible within a day, meaning that the individual industrial plants would need storage capacity for one day along with adequate electrolyser capacity.

In Figure 25, the resulting change in offshore wind power capacity with an increasing shift to hydrogen can be seen for all analysed scenarios.

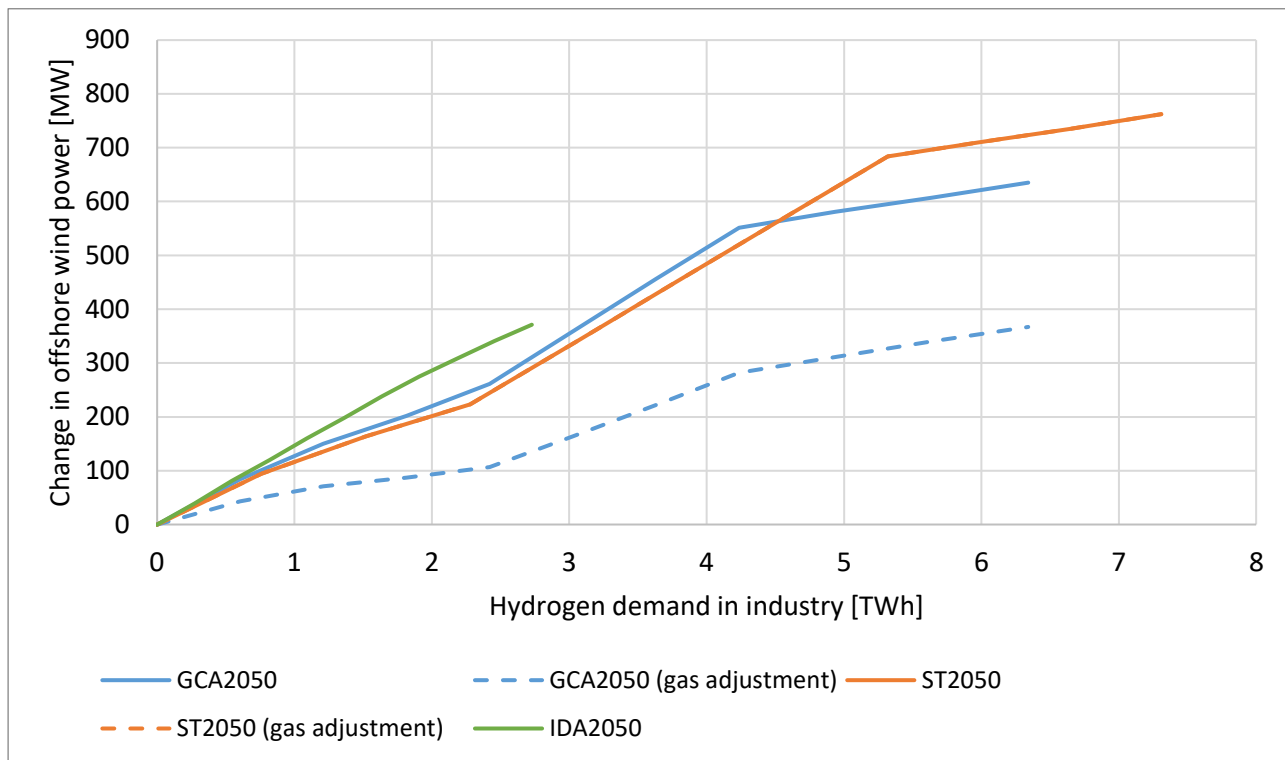


Figure 25 - The change in offshore wind power capacity made in each scenario at different levels of hydrogen fuel input for high-temperature processes in the industry.

A consistent trend can be observed for all scenarios; as the share of hydrogen increases, an increased offshore wind power capacity can be installed without increasing the CEEP of the system. The results for the GCA2050 and GCA2050 (gas adjustment) scenarios are different due to the difference in methodology, where the GCA2050 (gas adjustment) has a reduced biogas hydrogenation production and thus reduced electrofuel demand, offsetting some of the increased electricity demand. That is not the case for the ST2050 scenario as the biogas hydrogenation production is so low that it is not considered for this analysis, leading to the result shown with no difference for the two methodologies. A distinct flattening of the curve appears eventually for all Energinet scenarios, but not for the IDA scenario. This curve flattening happens once the entirety of the original renewable gas demand has been converted to a hydrogen demand, and any further expansion of hydrogen is subtracted from the industrial electricity demand instead. This is not the case for the IDA scenario because of the principle of balancing gas exchange to a yearly net-zero.

In Figure 26, the resulting change in biomass consumption with increasing use of hydrogen in the industry sector can be seen for all analysed scenarios.

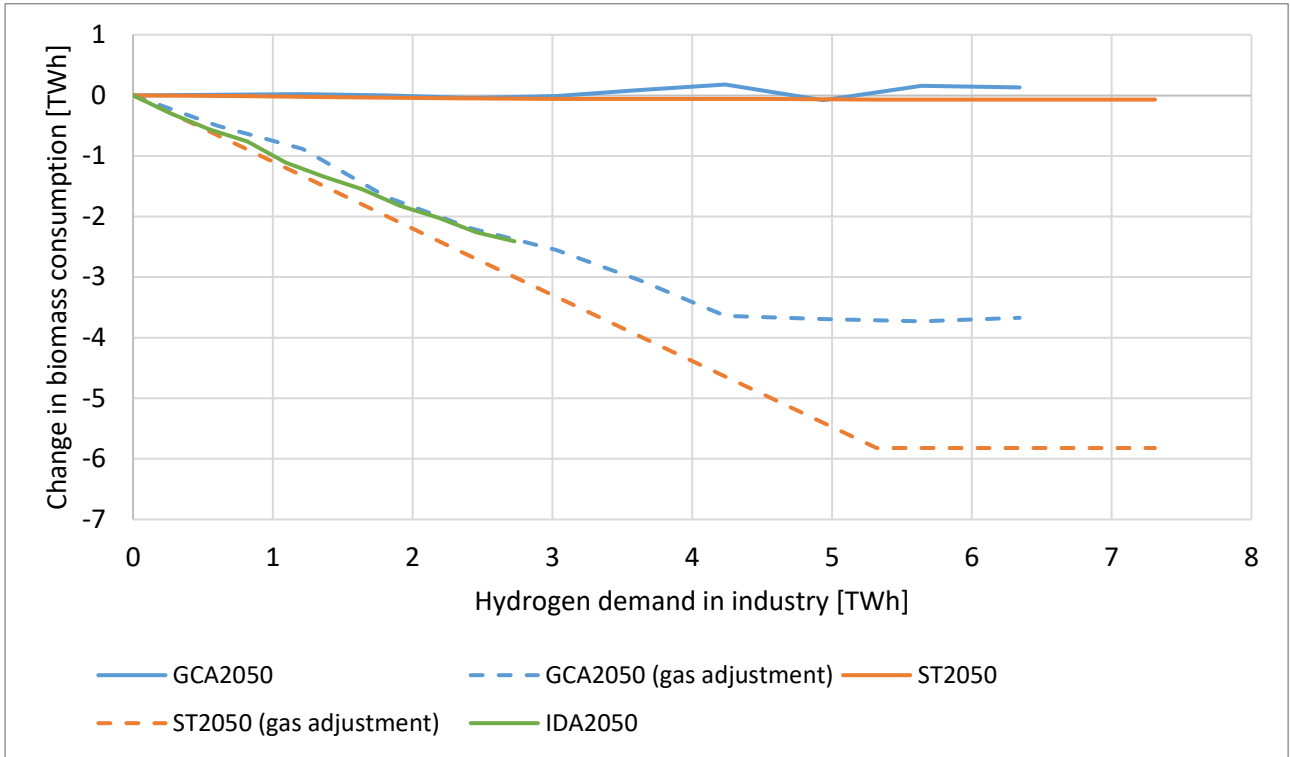


Figure 26 - The change in biomass consumption at different levels of hydrogen fuel input.

The change in biomass seen in Figure 26 show a trend similar to what was observed for direct electrification; an increasing electrification rate, or in this case indirect electrification through hydrogen processes, can reduce the biomass consumption of the energy system. However, this requires the gas supply side to be adjusted concurrently, as it is apparent looking at the results for the GCA2050 and ST2050 scenarios. If the gas production remains unchanged, the system will simply export any excess production, thus effectively negating any potential savings obtained from the fuel shift in the industry sector.

Looking at the change in energy system costs in Figure 27 and Figure 28, it can be seen that the differences in system design for the scenarios by Energinet and IDA respectively result in very different results.

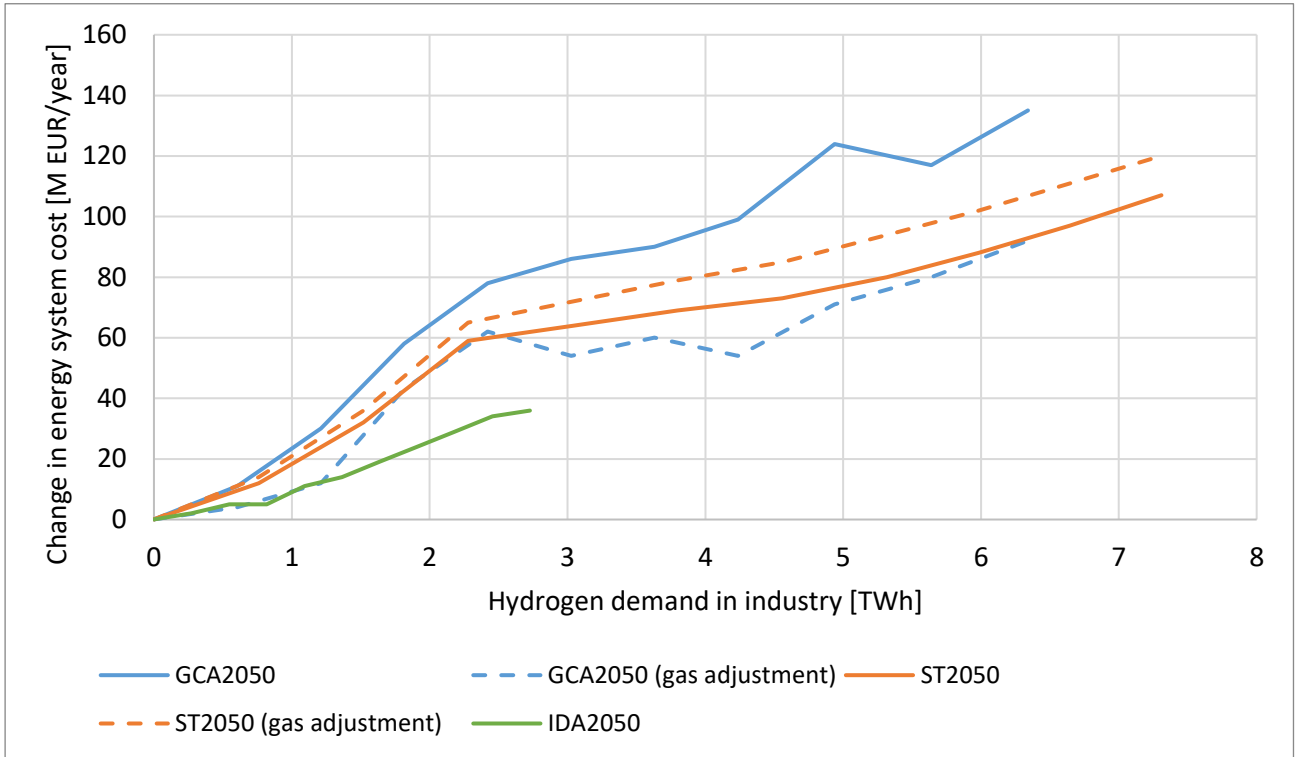


Figure 27 - The change in energy system costs at different levels of hydrogen fuel input.

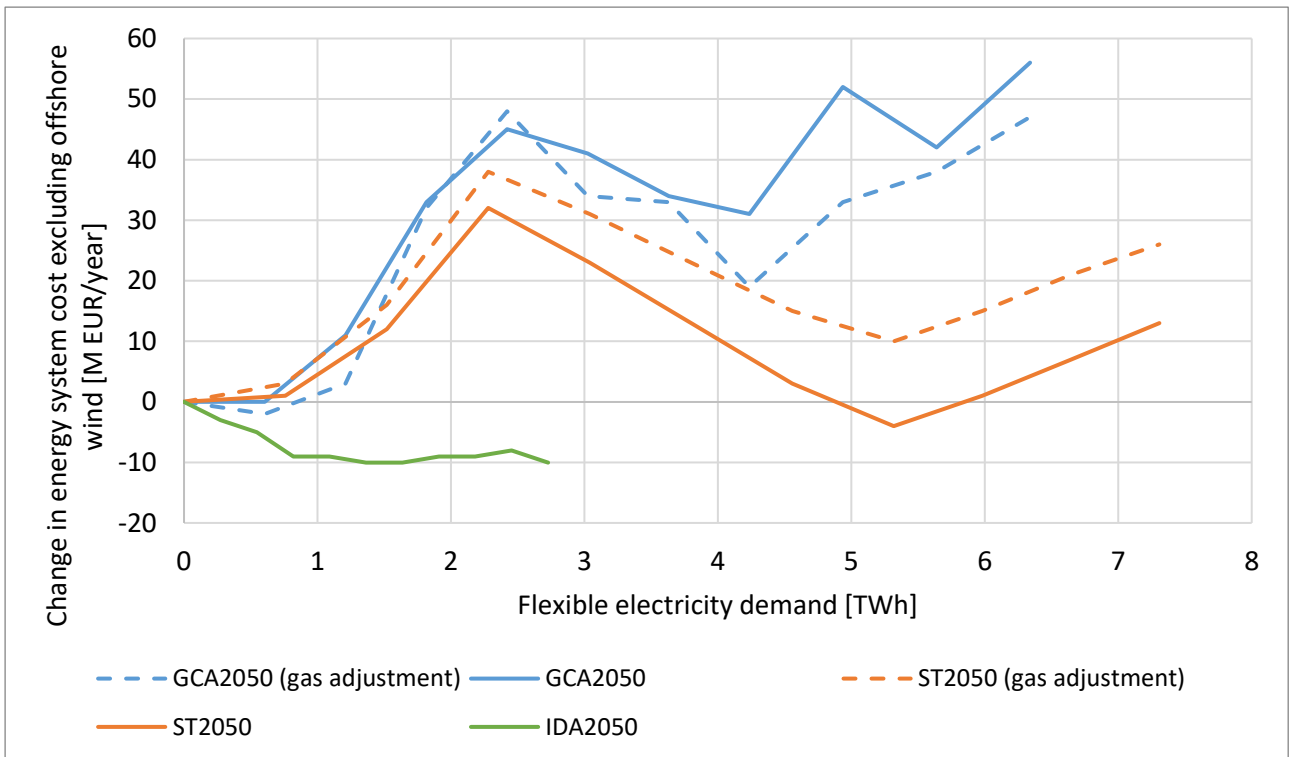


Figure 28 - The change in energy system cost, excluding the investment cost for wind power at different levels of hydrogen fuel input.

The results for the IDA scenario in Figure 27 show a relatively straightforward trend of increasing energy system cost as the demand for hydrogen in industry increases. The Energinet scenarios are also trending

upwards, but generally, show more significant fluctuations and variations. First of all, the general explanation for the increasing system cost across all scenarios shown in Figure 27 is that the installed offshore wind power capacity increases and thereby also the associated investment costs. This is the primary reason for the change in system cost for the IDA scenario, as it is illustrated in Figure 28 where the wind power investment is excluded, and energy system cost reductions can be obtained.

In Figure 28, the ST2050 and GCA2050 scenarios by Energinet show large variations depending on the amount of the industrial energy demand that is shifted to hydrogen. What happens is that a biogas demand is being shifted indirectly to an electricity demand based on electrolyser efficiency. Therefore, an increase in electricity demand in the system occurs, and because of the market economic simulation strategy applied and the principle of chronological simulation in EnergyPLAN changes to the electricity demand can result in large variations in electricity production, consumption, and import/export. In this case, the cost of electricity import increases a lot in the beginning due to importing during high price periods, however, after a hydrogen demand of 2.28 TWh the trend changes as the incremental increase in electricity import is profound, and savings elsewhere in the system (e.g. reduced biomass fuel consumption) can negate the increase in electricity import. This issue is exacerbated in the ST2050 and GCA2050 scenarios because of the low internal dispatchable production capacity, making the system susceptible to external market prices. Eventually, the trend changes again after 4 TWh to 5 TWh when a complete shift from biogas to hydrogen has occurred. This is because afterwards, the shift occurs from electricity to hydrogen, which results in a net increase in electricity demand due to electrolyser efficiency losses, which cannot be recovered through the increase in flexibility obtained from the 1-day hydrogen storage available at the industrial sites.

5.2.2 Electricity demand flexibility

As previously described, the flexibility of an energy system is a sum of many technologies and mechanisms. Some of these are already investigated in other analyses within this study, e.g. electricity storage, transportation demands, and P2X processes. This analysis will instead focus on the potential for demand flexibility within the traditional electricity demand, in particular demands flexible within a day. Figure 29 shows how this demand relates to the total electricity demand for the analysed scenarios.

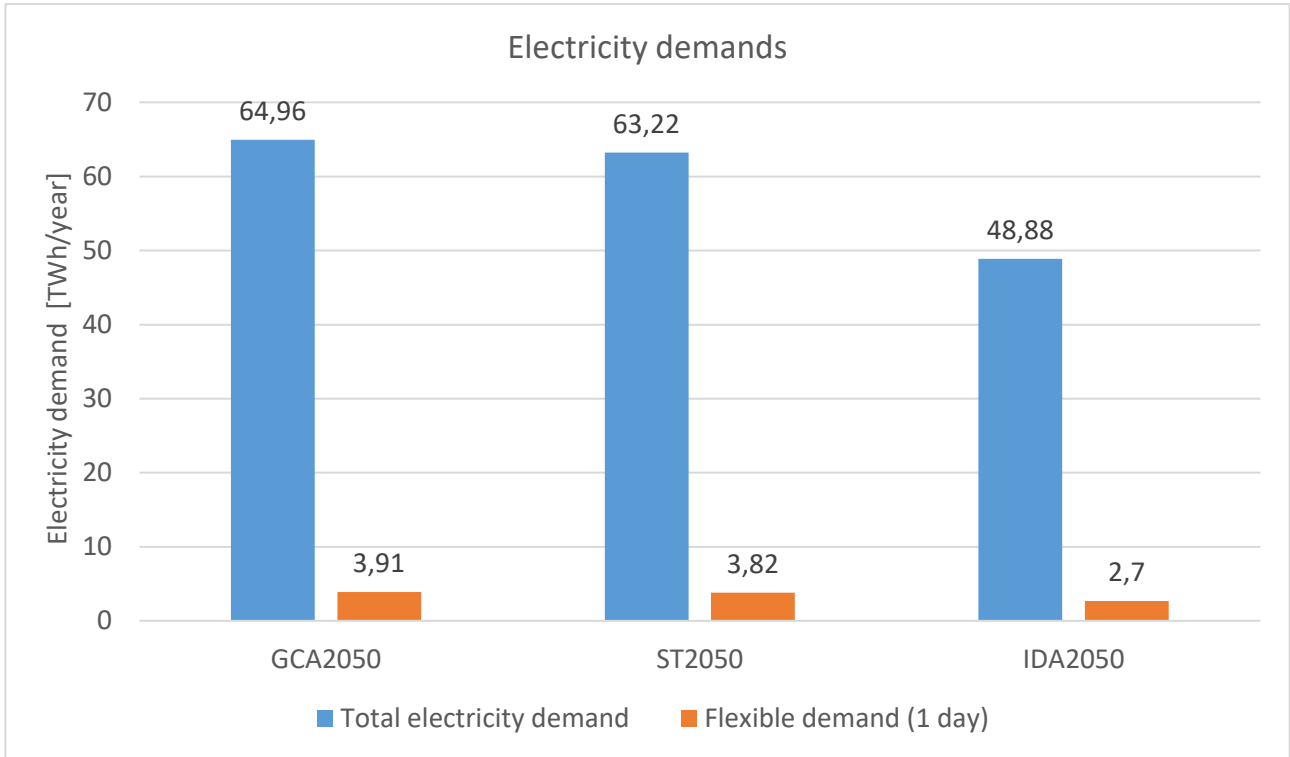


Figure 29 - Total electricity demand relative to flexible electricity demand for all analysed scenarios.

From Figure 29 it can be seen that across the different scenarios there are differences both in the total electricity demand and slight variations in what is assumed to be flexible within a day, with the most considerable deviations occurring for the IDA scenario. The extent to which the electricity demand can be flexible in the future is uncertain, and the value included in the references scenarios does not necessarily reflect the future system. It is therefore relevant to test a broader range of possibilities to consider possible benefits and energy system interactions of such flexibility. In the future, electricity demand flexibility could arise for example from a multitude of solutions, e.g. on a small-scale from typical households appliances such as coolers and freezers, but also on a larger scale from electric heating solutions such as electric HPs or electric boilers, ventilation systems, or batteries, all of which could be located in households, industries, or public buildings [43]. We do not, however, with this analysis dive into the array of specific mechanisms and measures needed to supply this flexibility but instead focus on the system benefits and interactions of electricity demand flexibility. The analyses are only conducted for 2050, where the flexibility potential is expected to be higher than 2035, but also more uncertain in terms of which technologies and measures will provide flexibility.

5.2.2.1 The flexibility of the traditional electricity demand

This analysis is only concerned with the flexibility of the traditional electricity demand, defined as the electricity demand for households and the industry sector, excluding individual HPs. Electricity for heating (e.g. electrification of the DH sector) and electricity for transportation is not considered to be part of the traditional electricity demand. There are significant flexibility potentials in other sectors such as heat and transport where, e.g. DH and P2X technologies can be used both for flexible production and energy storage. However, these solutions are covered in other sections of this study and will thus not be considered in this specific analysis limited to flexibility within the traditional electricity demand.

All three scenarios already include some flexibility of the traditional electricity demand, as it is seen in Figure 29. This analysis investigates the consequences of decreasing this flexibility to zero and increasing the flexibility to 250% of the potential included in the reference systems. The maximum effect (the power available for flexible operation) is changed linearly according to the amount of the flexible demand available based on the effect in the reference systems. Using this logic, an increase in the annual available flexible electricity demand results in an equal (relatively) increase in the maximum available effect. We consider this to be a valid assumption given the expectation that the increases to the flexible electricity demand will be due to an increasing number of units and technologies available for flexible consumption, hence increasing the available effect.

The methodology applied is the same for all three scenarios, but because the amount of flexible electricity demand included in the reference system varies for each scenario, the resulting flexible electricity demand also varies. This is most noticeable for the IDA scenario, where it is apparent that the highest flexible demand tested is less than the highest demand tested for the ST and GCA scenarios - simply because the starting point in the IDA reference system is low as well. The scenario modelling conducted in EnergyPLAN applies the general principles described in the methodology chapter, e.g. balancing of offshore wind power capacity to the original CEEP value, and net gas zero-sum balancing for the IDA scenario. The resulting change in offshore wind power capacity with varying levels of flexibility in the electricity demand can be seen in Figure 30.

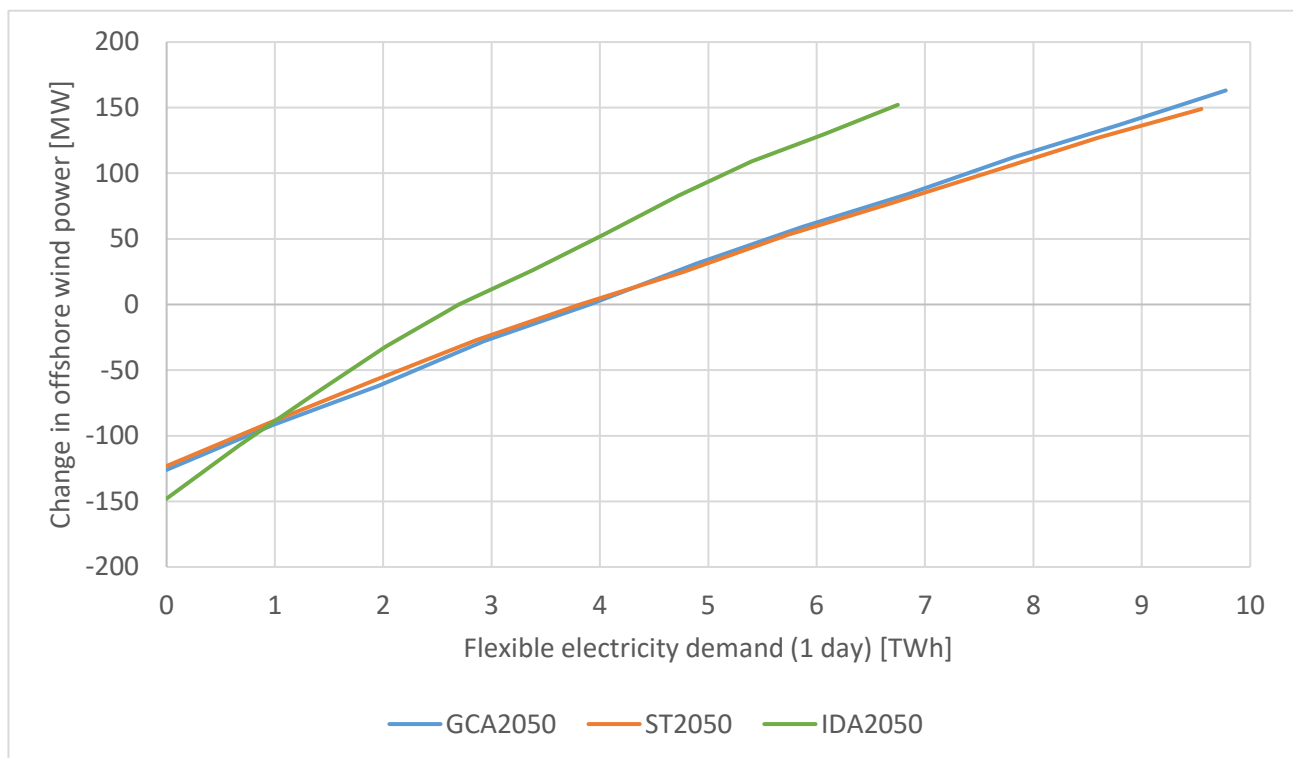


Figure 30 - The change in offshore wind power capacity made in each scenario at different levels of flexibility in the traditional electricity demand.

A distinct trend can be observed for all three scenarios in Figure 30; the potential for installing offshore wind power increases as the flexible electricity demand increases. This is to be expected, as increased flexibility enables the system to integrate more of the fluctuating production from the wind turbines and thus makes it possible to increase the installed capacity without increasing CEEP in the system. There are no significant

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differences in the results for the ST2050 and GCA2050 scenarios as the modelling approach for these two scenarios is similar. For both ST2050 and GCA2050, the increased production from offshore wind turbines results in a decrease in the import of electricity. The IDA2050 scenario responds slightly different, as the increased VRE production mainly causes reduced production on the power plants, and only to a lesser extent reduces the import of electricity.

In Figure 31, the resulting change in biomass consumption can be seen for the three scenarios.

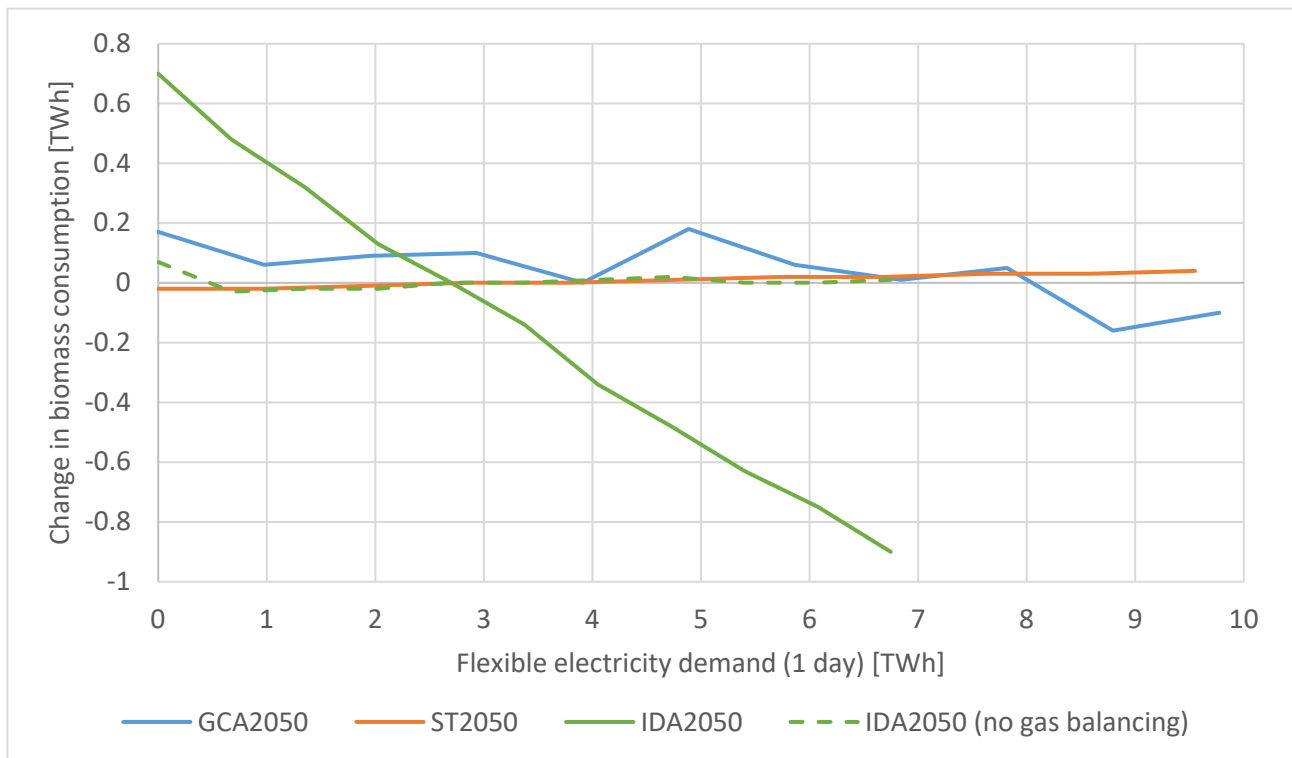


Figure 31 - The change in biomass consumption for each scenario at different flexibility levels.

The first thing to consider when looking at the results from Figure 31 is that the absolute differences in biomass consumption are relatively low; thus the fluctuations may appear to be more significant than what is the case. However, the IDA2050 scenario stands out from the ST2050 and GCA2050 in the sense that a clear trend of decreasing biomass consumption as the flexible electricity demand increases can be observed. This is due to differences in modelling, where the import and export of gas in the IDA scenario are balanced to a yearly net-zero by adjusting the biomass gasification production; a principle that is further described in section 3.4. Because of this principle, the reduced operation of the power plant results in reduced consumption of gas and therefore a reduced gas production and thus biomass consumption for the system. This is clear when looking at the result for the IDA2050 (no gas balancing) scenario, where it can be seen that without the gas balancing principle the IDA scenario does not experience the decrease in biomass consumption. Therefore, for changes to the flexibility of the traditional electricity demand, reductions in biomass consumption is dependent on the methodological modelling principle applied more so than the energy system design.

In Figure 32, the changes to the total energy system cost can be seen for all the scenarios.

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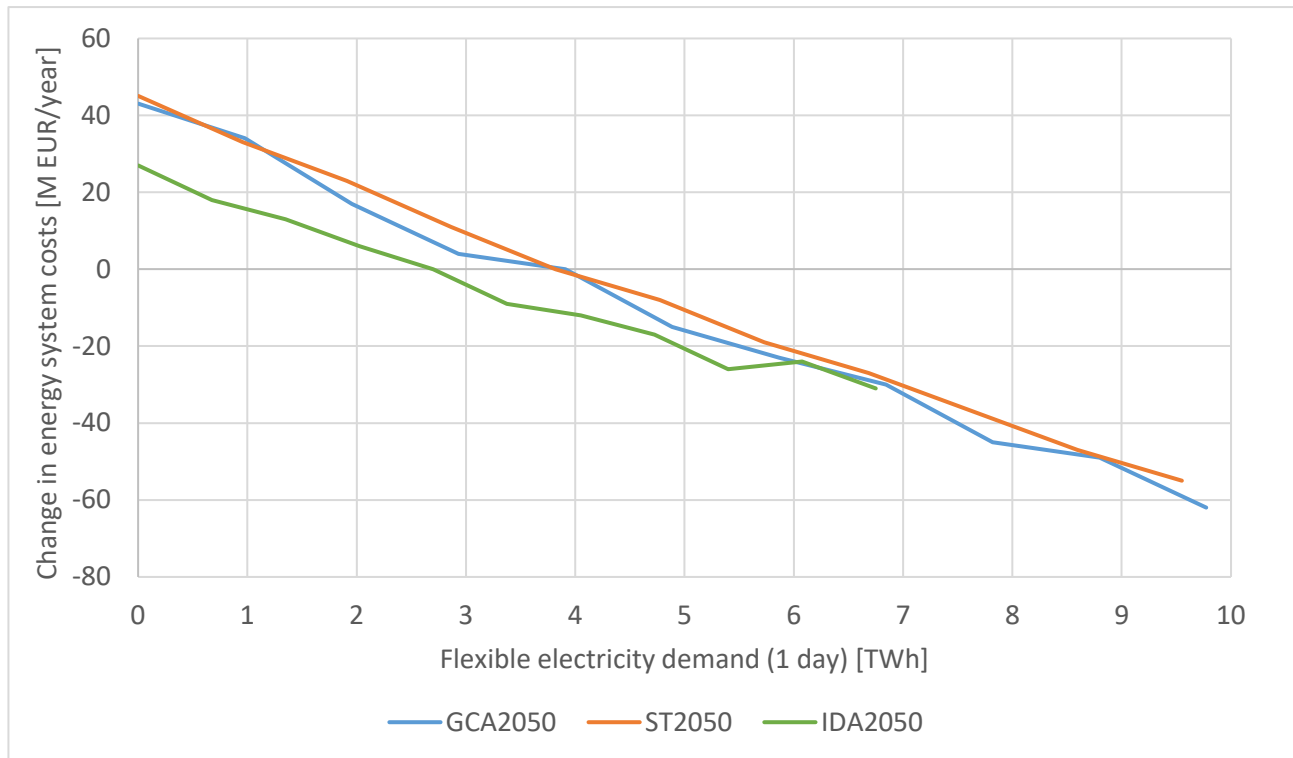


Figure 32 - The change in energy system costs for each scenario at different flexibility levels.

In all scenarios, the total system cost decreases as the flexibility of the electricity demand increases, despite an increased investment cost for additional offshore wind turbines. This is not surprising, considering how additional flexibility enables integration of more low-cost VRE. However, what may be surprising is that the reasons behind this decrease in system cost vary for the different scenarios. This is illustrated in Table 3, showing the changes to electricity import and import cost for each scenario.

Table 3 - The change in net electricity import and the correlated net import cost for each scenario at different flexibility levels. 100% corresponds to the flexibility included in the reference system.

	GCA2050	ST2050	IDA2050	GCA2050	ST2050	IDA2050
Flexibility	Change in net electricity import [TWh]			Change in net electricity import cost [M EUR]		
0%	0.22	0.44	0.28	40	53	12
25%	0.20	0.33	0.21	35	38	9
50%	0.05	0.19	0.14	11	26	7
75%	-0.08	0.08	0.07	-7	11	3
100%	0.00	0.00	0.00	0	0	0
125%	-0.35	-0.09	-0.05	-37	-11	-7
150%	-0.30	-0.18	-0.06	-36	-23	-3
175%	-0.19	-0.26	-0.11	-32	-34	-4
200%	-0.45	-0.36	-0.16	-61	-47	-11
225%	-0.16	-0.45	-0.18	-39	-58	-6
250%	-0.33	-0.51	-0.20	-61	-66	-9

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In Table 3, it is seen that all scenarios experience decreases in the net import of electricity as flexibility increases; however, it is most apparent in the ST2050 and GCA2050 scenarios, and least in the IDA scenario. In all scenarios, the net electricity import cost also decreases as flexibility increases, but the GCA2050 and ST2050 scenarios are more influenced by flexibility than the IDA scenarios. This is likely due to the smaller installed power plant capacity, making the GCA2050 and ST2050 more reliant on electricity import, even during high price periods. Because of a large power plant capacity, compared to the GCA2050 and ST2050 scenarios, the IDA scenario can avoid importing electricity when the external market price is very high, thus limiting the influence electricity demand flexibility on the import cost.

The modelling of electricity demand flexibility did not include a specific cost of increasing flexibility potential, but from the results shown in Figure 32, the value provided to the system can be derived. Based on linear trendlines for the results in Figure 32, a decrease in total annual system cost of between 8.52 M EUR and 10.55 M EUR can be observed; therefore, from a strictly energy system point of view, the value of flexibility is between 8.52 EUR and 10.55 EUR per MWh electricity that can be flexible within a day, not counting potential investments needed for ensuring this flexibility.

It is difficult to make a definitive conclusion on whether it is realistic to shift part of the traditional electricity demand to a flexible demand at this cost; for one thing, it is far below the cost of battery storage. However, the purpose is also merely shifting (delaying) demand, and storage is not necessarily required in this case. In a study on the energy efficiency of households in smart energy systems by SWECO and EA Energianalyse [43], it was concluded that shifting demand, e.g. cooling, freezing, and ventilation units would not be cost-effective based solely on spot price fluctuations assuming that flexible units would be more expensive. However, if only minor or no increase in cost was included, the increased flexibility was economically beneficial to the system, similar to the result of this study. This would require that the necessary technology is included in products as a standard. SWECO and EA Energianalyse found that other areas such as electric heating is cost-effective in blocks of flats and institutions, but not in single-family households. In the same study, batteries were also found not to be cost-effective but could be relevant for flexibility if installed primarily for other purposes [43].

Changes to electricity tariff rates may also be a way of incentivizing demand flexibility and thus aid in shifting part of the electricity demand. Energinet, the Danish TSO, is implementing a tariff “discount” for large-scale consumers willing to be interrupted [44]. An approximate discount of 25% is proposed, which given the current transmission tariff rates in 2020 equals approximately 2.5 EUR/MWh; however, this is not the same flexibility as what was tested in the model, as it is a permanent discount to the tariff rates for agreeing to terms allowing Energinet to interrupt electricity supply. The purpose is also different as it is not explicitly meant as a mechanism to shift electricity demand throughout the day to optimize the integration of VRE, but a mechanism to assist Energinet in their long-term planning on the need for grid expansion.

Danish distribution system operators are also exploring the possibility of changing tariff schemes to incentivize flexible consumption. One way of doing so is by implementing time differentiated prices as opposed to the traditional flat-rate volume-based tariff rate. This has been done by several distribution system operators already for parts of their distribution area, including Radius [45], Konstant [46] and Cerius [47]. In all three examples daily price differentiation is implemented with three different price periods: low price, high price, and peak price, with an approximate tariff reduction of 40% for low price periods during the late evening and

night-time. This results in tariff reductions of approximately 2 to 3 EUR/MWh during low price periods compared to the standard flat-rate tariffs. Such reductions may not be enough to provide the amount of flexibility included in this analysis, but it is nevertheless an example of how established actors are working towards implementing flexibility mechanisms.

5.2.3 Grid-scale electricity storage

The ST, GCA, and IDA reference models do not include electricity storage options and instead rely on other flexibility options such as HPs in DH coupled with heat storage and other power-to-X technologies. Hence, investigating the role and potential of electricity storage may provide value to a future renewable energy system with a high degree of VRE production.

The purpose of the following analysis is to test large grid-scale/utility-scale electricity storage solutions regarding the system flexibility provided and potential for integration of wind power. The focus is not on cost optimization of the storage operation, and therefore it is chosen to apply a technical simulation strategy as opposed to the market economic simulation applied in most other analyses within this study. In the technical simulation strategy, EnergyPLAN will seek to minimize the import/export of electricity and the fuel consumption of the system, thus making it suitable for this investigation of system flexibility and VRE integration.

This analysis will investigate two vastly different electricity storage solutions: grid-scale li-ion batteries and high-temperature rock bed storage. While many other potential technologies exist, as mentioned previously, these two do cover a broad spectrum. Grid-scale li-ion batteries are a well-established established technology and are installed throughout the world. Enormous potentials for growth remains as costs are expected to decrease in the future, but it is uncertain by how much as the price reduction expected by The Danish Energy Agency and Energinet [48] range from 6% (upper price boundary) to 84% (lower price boundary). High-temperature rock bed storage is an emerging technology with applications in pilot projects, but limited utility-scale use beyond that. Thus, these technologies are drastically different in terms of their development stage. Technically, li-ion batteries and high-temperature rock bed storage are also very different solutions in that the first employ chemical storage while the latter relies on thermal storage. However, for this analysis, it is not critical to include all possible electricity storage technologies, as the emphasis is not on the technological functionality, but instead on the system flexibility and integration benefits.

5.2.3.1 *Li-ion battery storage*

Li-ion batteries have in recent years experienced a price decrease and predicting how the prices will develop going forward is difficult, especially for long time horizons like 2035 and 2050. Therefore, to avoid merely speculating on what the price may be in the future, the model does not include costs for the batteries installed. This approach instead identifies the energy system benefits (and thus economic savings) obtained, from which discussions can arise on what may be a feasible price to pay for battery storage in future energy systems.

The installed battery capacity is derived based on the average hourly conventional electricity demand for the IDA2050 scenario, with the maximum battery capacity being equal to 24 hours of electricity storage. This results in 13 different scenarios with varying installed battery capacity, as illustrated in Table 4. The battery capacities are applied to all energy systems tested (GCA, ST, IDA).

Table 4 - Battery capacity relative to hours of storage at average hourly conventional electricity demand for IDA2050.

Hours of storage [h]	0	2	4	6	8	10	12	14	16	18	20	22	24
Battery capacity [GWh]	0	8	16	24	32	40	48	56	64	72	80	88	96

The scenario modelling conducted in EnergyPLAN applies the general principles described in the methodology chapter, e.g. balancing of offshore wind power capacity to the original CEEP value, and yearly net zero gas balancing for the IDA2050 scenario. The balancing of offshore wind power capacity takes place in a closed system, i.e. a system without transmission line capacity. This is to find out how the batteries affect the operation of the energy system and the internal balancing of CEEP, as such differences in operation are likely to be cancelled out by a large transmission line capacity. After a new offshore wind power capacity has been identified in the closed system (the largest possible capacity that does not cause an increase in CEEP), the transmission line capacity is again added to the system, and a new simulation is conducted. This methodology is particularly important for this analysis of battery storage, as EnergyPLAN will by default first choose to export excess electricity before charging the battery storage if transmission capacity is available, which in practice results in the batteries receiving almost no electricity for charging. It may, however, also be relevant to see how the system operation is impacted if the batteries are prioritised before transmission to limit the import and export of electricity. To investigate this, additional simulations are completed in which part of the transmission capacity is removed from the system and instead added as additional power plant capacity (PP1) in EnergyPLAN as a proxy for the transmission capacity. By doing so, EnergyPLAN can prioritise operation of the batteries above export of electricity, which would otherwise be the default approach. There is no strictly correct simulation approach as the choice largely depends on what the modeller considers the role of battery storage to be, and hence what priority batteries should receive relative to external transmission. The analysis on li-ion batteries will, therefore consider results for both of these simulation approaches. Std indicates results based on the standard approach (i.e. with traditional transmission capacity), while Alt indicates results based on the alternative approach (i.e. transmission capacity converted to PP1).

The implemented changes to the model are shown in Table 5.

Table 5 - Transmission and PP1 capacity for Std. and Alt. scenarios. Changes are implemented to Alt. scenarios to prioritise batteries for system balancing.

[MW]	GCA2035	ST2035	IDA2035	GCA2050	ST2050	IDA2050
Std. transmission	12,735	10,435	7,100	12,735	10,435	7,100
Alt. transmission	4,735	2,435	3,100	4,735	2,435	3,100
Std. PP1	2,491	2,111	4,500	391	391	4,500
Alt. PP1	10,491	10,111	8,500	8,391	8,391	8,500

The change in offshore wind power capacity resulting from varying the installed battery capacities can be seen in Figure 33. The change in offshore wind power capacity is not dependent on the simulation approach chosen, as the assessment of potential offshore wind power capacity relative to CEEP value is based on a closed energy system.

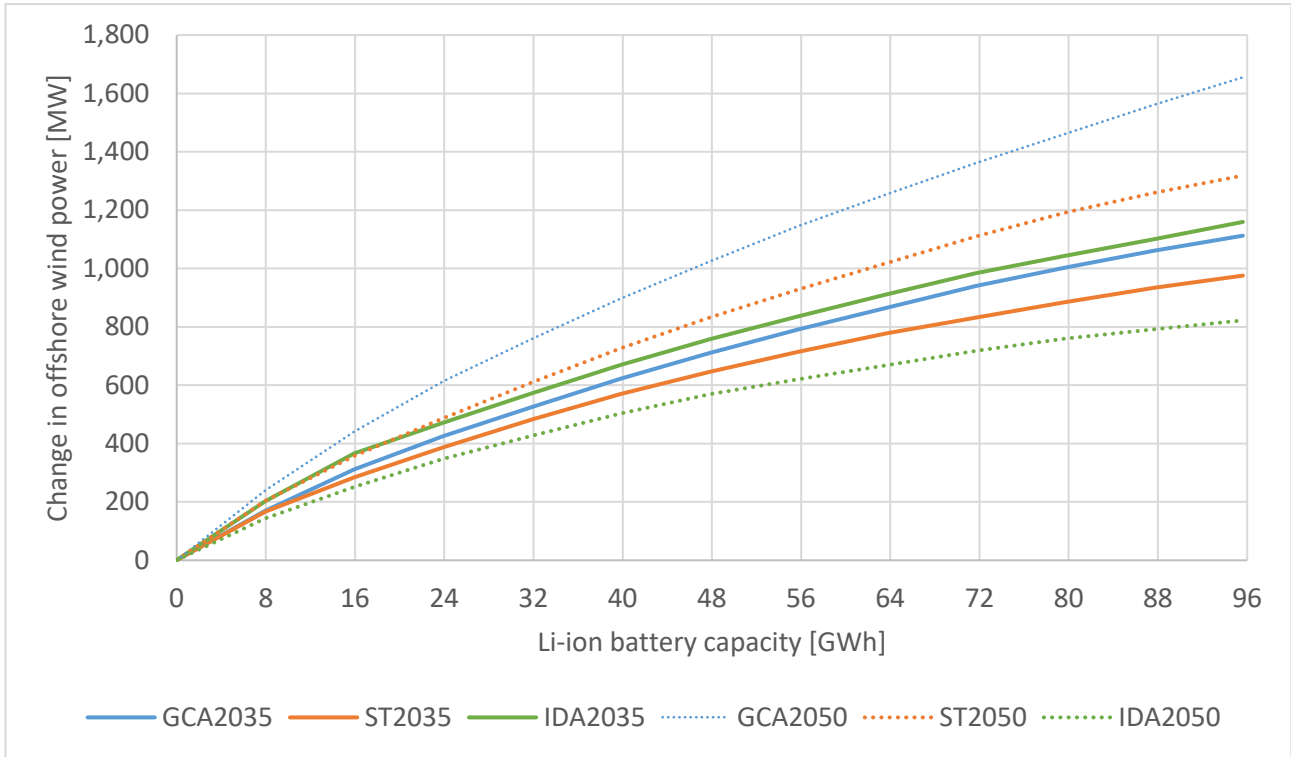


Figure 33 - The change in offshore wind power capacity in each scenario at different capacities of li-ion batteries (Std. simulation).

In all scenarios, it is possible to increase the offshore wind power capacity by 800 MW to 1,600 MW without increasing the CEEP value. This is a logical outcome from increasing the battery capacity, as VRE production that would otherwise have been categorized as CEEP due to a lack of demand and storage options can now be stored and discharged later. While the general trend is the same for all systems (GCA, ST, IDA), there is some variation in how much capacity can be installed without increasing CEEP. Exactly how much can be installed is mainly based on the extent to which flexibility measures are already included in the system, e.g. in the form of electrolysers, hydrogen storage, electric boilers, and thermal storage. This shows when looking at the results for IDA2050 which has a broad array of flexibility options; thus the increase in battery capacity is less effective in increasing the maximum offshore wind power capacity relative to the reference scenario.

Figure 34 and Figure 35 shows the change in import and export of electricity for the 2035 and 2050 scenarios, and illustrate the challenge linked to the default simulation strategy for batteries in EnergyPLAN.

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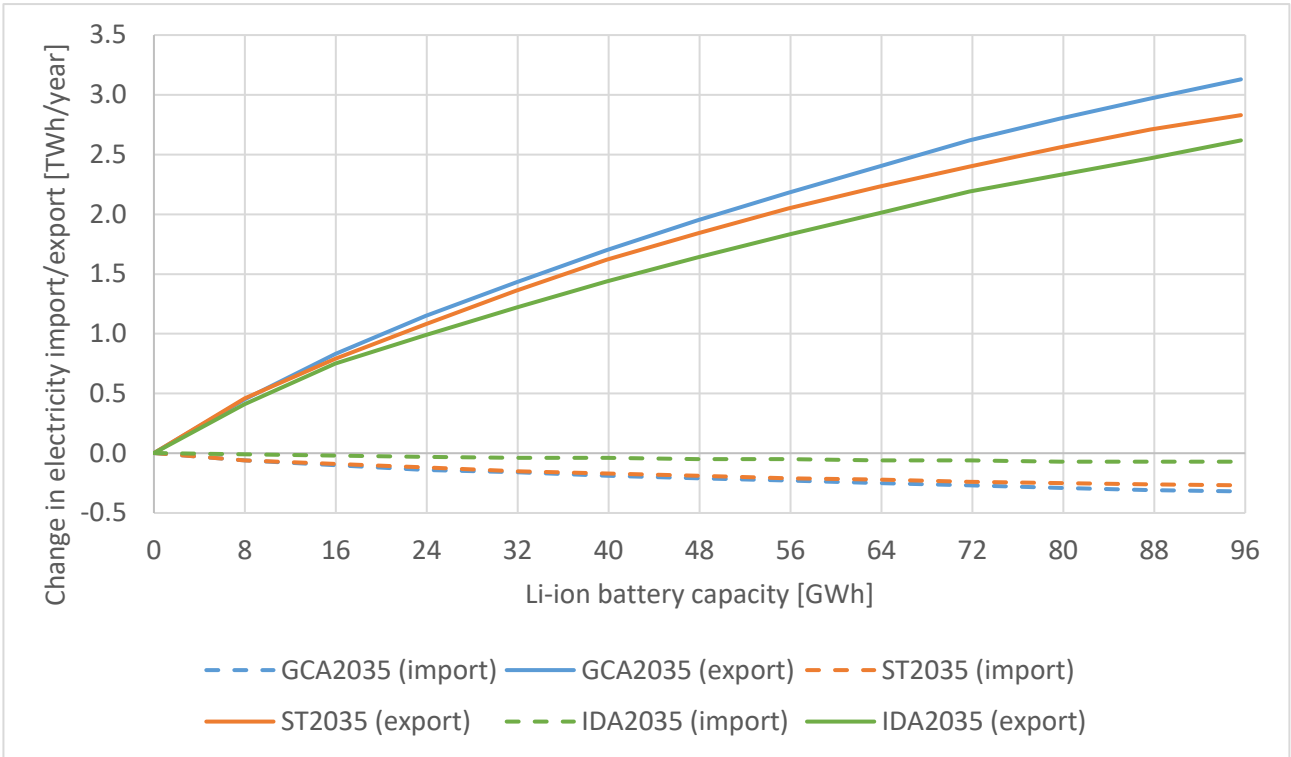


Figure 34 - The change in electricity import and export in each 2035 scenario at different capacities of li-ion batteries (Std. simulation).

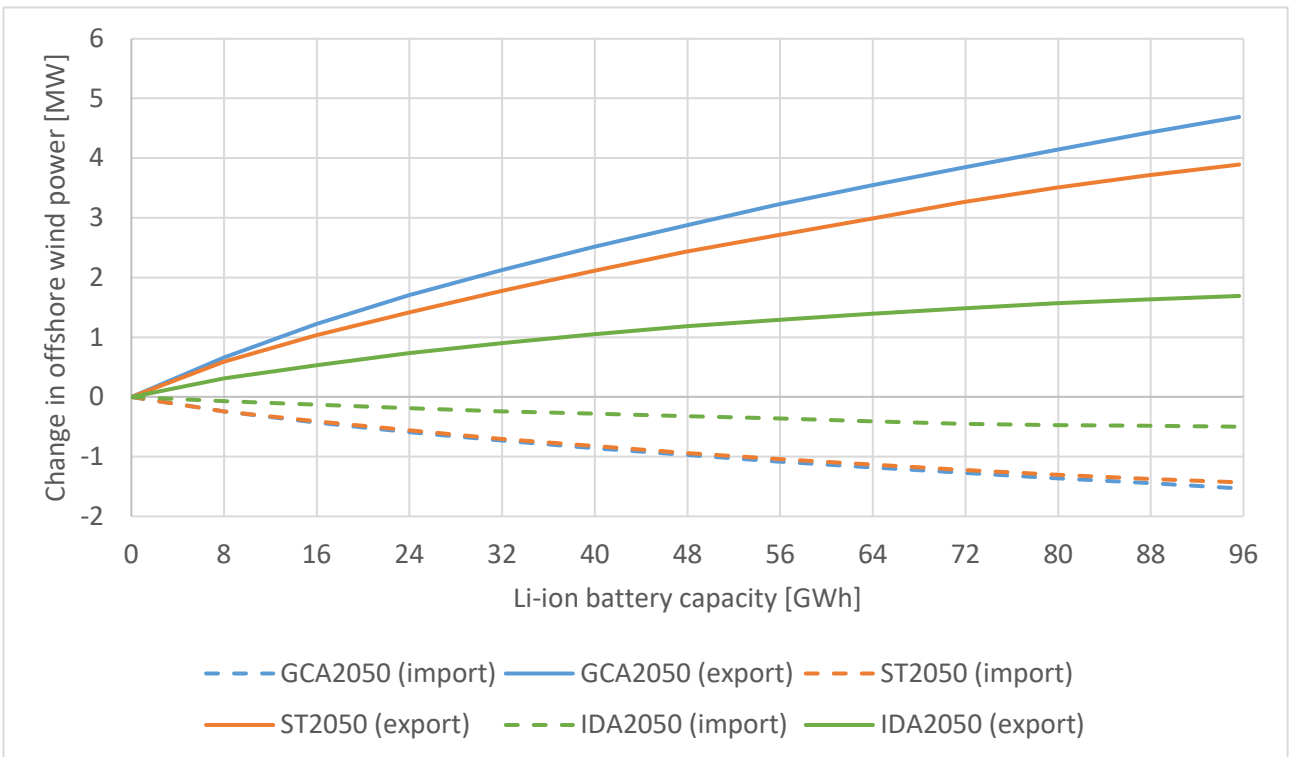


Figure 35 - The change in electricity import and export in each 2050 scenario at different capacities of li-ion batteries (Std. simulation).

Across all three systems, a similar trend can be observed in Figure 34 and Figure 35. As the installed battery capacity increases, so does the export of electricity. This is because of more massive production of VRE due

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to the increased offshore wind power capacity. However, this is primarily because of the large transmission capacity available, and because as previously mentioned, EnergyPLAN will first prioritize exporting excess electricity before charging battery storage, hence the increase in export of electricity occurs. Grid-scale batteries could arguably also serve a role in limiting the import and export of electricity, and therefore the Alt. simulation results are also included.

As previously mentioned, the Alt. simulation bypasses the default prioritization strategy in EnergyPLAN by transferring part of the transmission capacity to power plant (PP1) capacity. The change in import and export can be seen for the Alt. 2035 scenarios in Figure 36 and Figure 37.

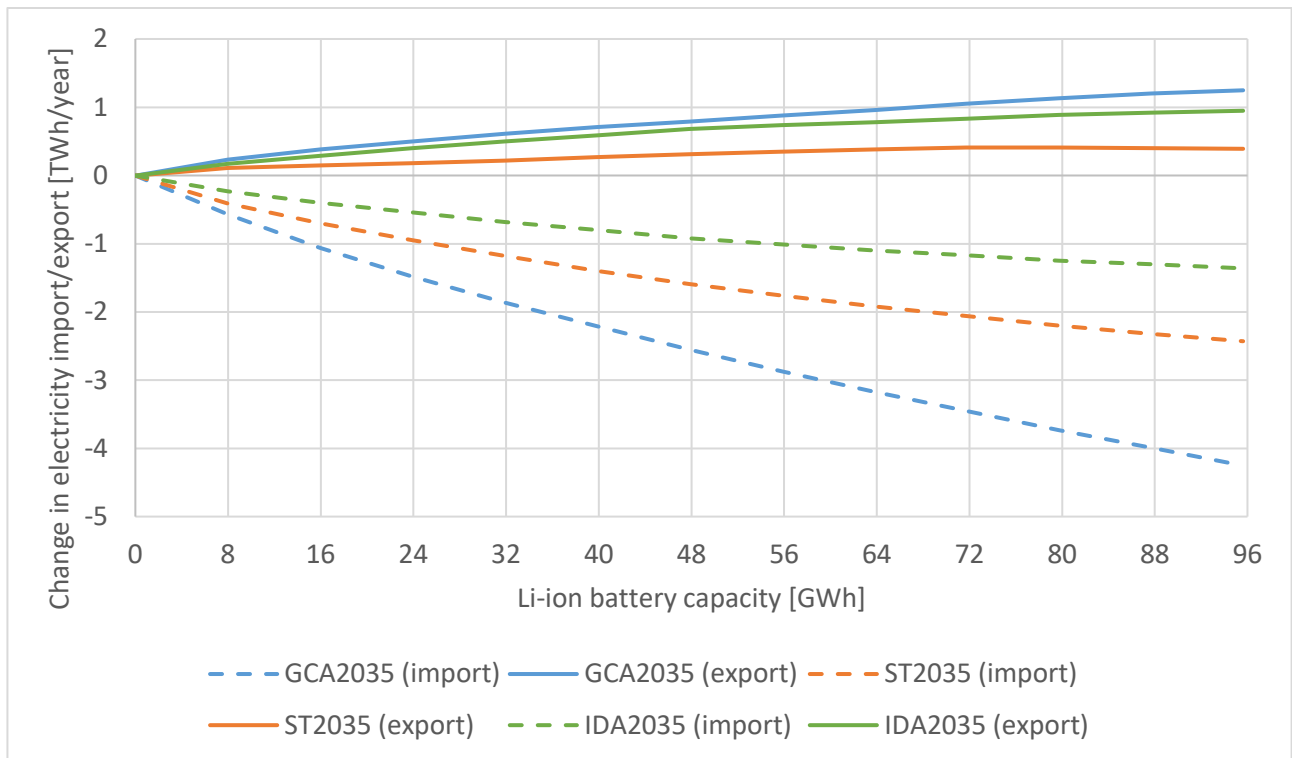


Figure 36 - The change in electricity import and export in each 2035 scenario at different capacities of li-ion batteries (Alt. simulation).

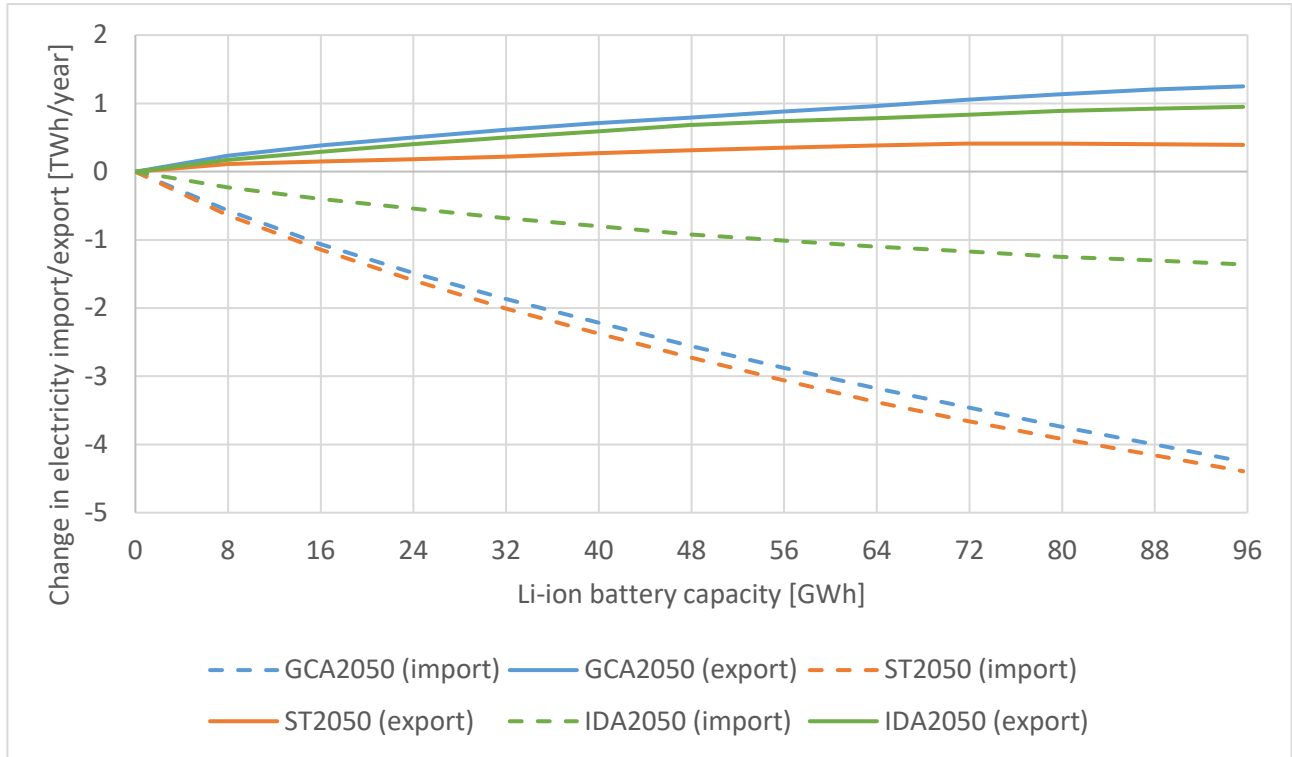


Figure 37 - The change in electricity import and export in each 2050 scenario at different capacities of li-ion batteries (Alt. simulation).

In the results for the Alt. simulations shown in Figure 36 and Figure 37 it can be seen that the increase in electricity export is less prevalent than it was in the Std. simulations, and also that the import of electricity decreases more. This indicates that as the installed battery capacity increases, so does their ability to balance excess VRE production internally and limit the import of electricity. How the batteries should be operated is, however, mainly a modelling and methodological consideration, and one method is not inherently better than the other.

In all scenarios, independent of the simulation approach, increasing the installed battery capacity does not significantly decrease the peak electricity import, as the effect is only between 0 MW to 38 MW. Whether the peak import can be decreased is linked to both what other flexibility options are available in the system, e.g. dispatchable power production like power plants and CHP plants, but is also a result of the applied modelling approach and if limiting the use of transmission lines is an objective of the model which by default is not the case for EnergyPLAN.

In Figure 38, the change in biomass consumption can be seen for each scenario.

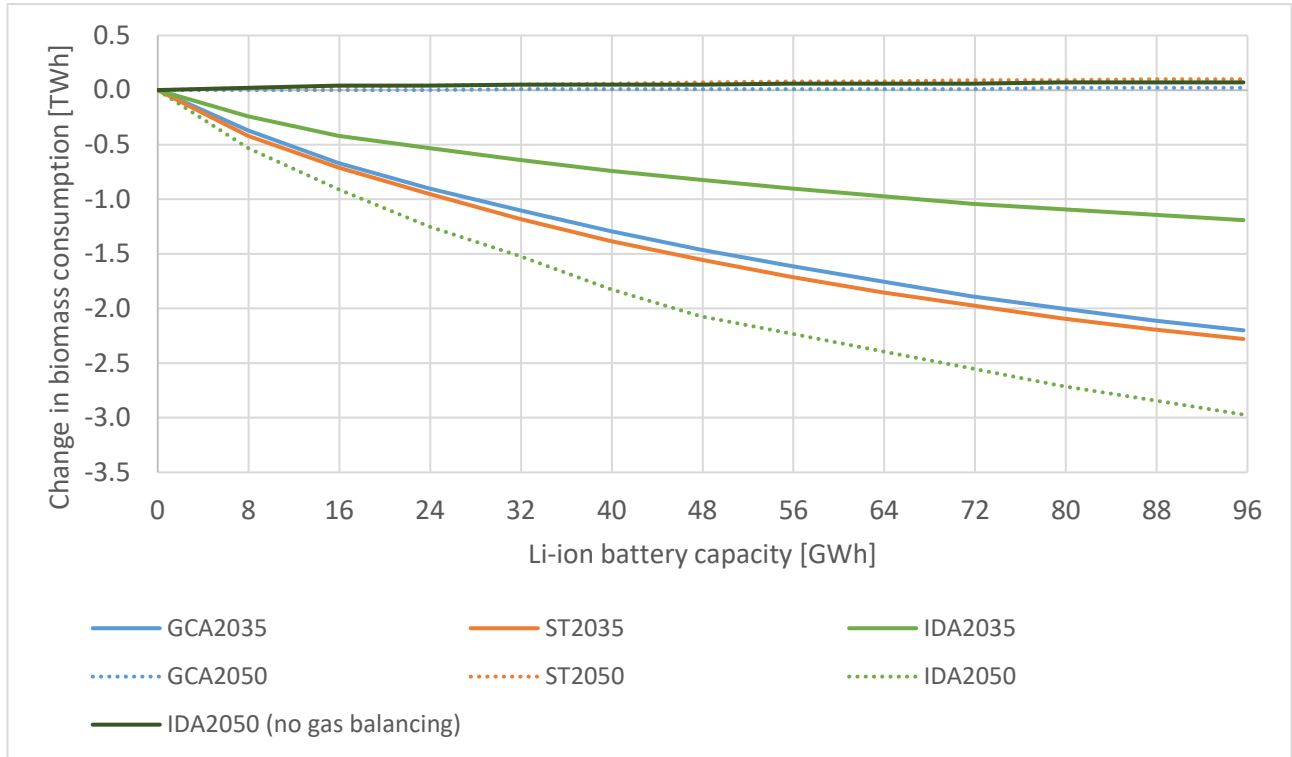


Figure 38 - The change in biomass consumption in each scenario at different capacities of li-ion batteries (Std. simulation).

The results for ST2035 and GCA2035 are similar with regards to changes in biomass consumption, where the decrease is more extensive than for the IDA2035 scenario. In principle, the 2035 scenarios respond similarly in the sense that increasing the battery capacity results in a reduced operation of the large power plants and CHP plants, thus reducing the biomass fuel consumption. The difference between the IDA2035 and the 2035 Energinet scenarios occurs because of a difference in assumed fuel distribution for power plants and CHP plants. The IDA2035 scenario assumes 50% of fuel to be supplied by biomass and 50% by gas, whereas the Energinet scenarios assume 83% and 87% biomass fuel, resulting in a difference in how much the biomass fuel consumption can be reduced. For the 2050 systems, a significant difference can be observed when comparing the Energinet systems to the IDA system. This is mainly because of the modelling principle applied for the IDA2050 system where the import and export of gas are balanced by adjusting the biomass input to the gasification plant. This is not the case for the Energinet scenarios, where the biogas and electrofuel production remains unchanged and therefore does not decrease the biomass consumption. To illustrate that the difference is caused by the gas balancing principle applied in IDA2050, a simulation was also done without gas balancing, which shows the same tendency as in the Energinet 2050 scenarios. To a lesser extent, some minor differences occur for the 2050 scenarios due to differences in also because of the low CHP and power plant capacity in the 2050 Energinet scenarios, and thus only minor biomass fuel reductions can be realised there.

In Figure 39, the changes in energy system cost, excluding offshore wind power can be seen for all scenarios.

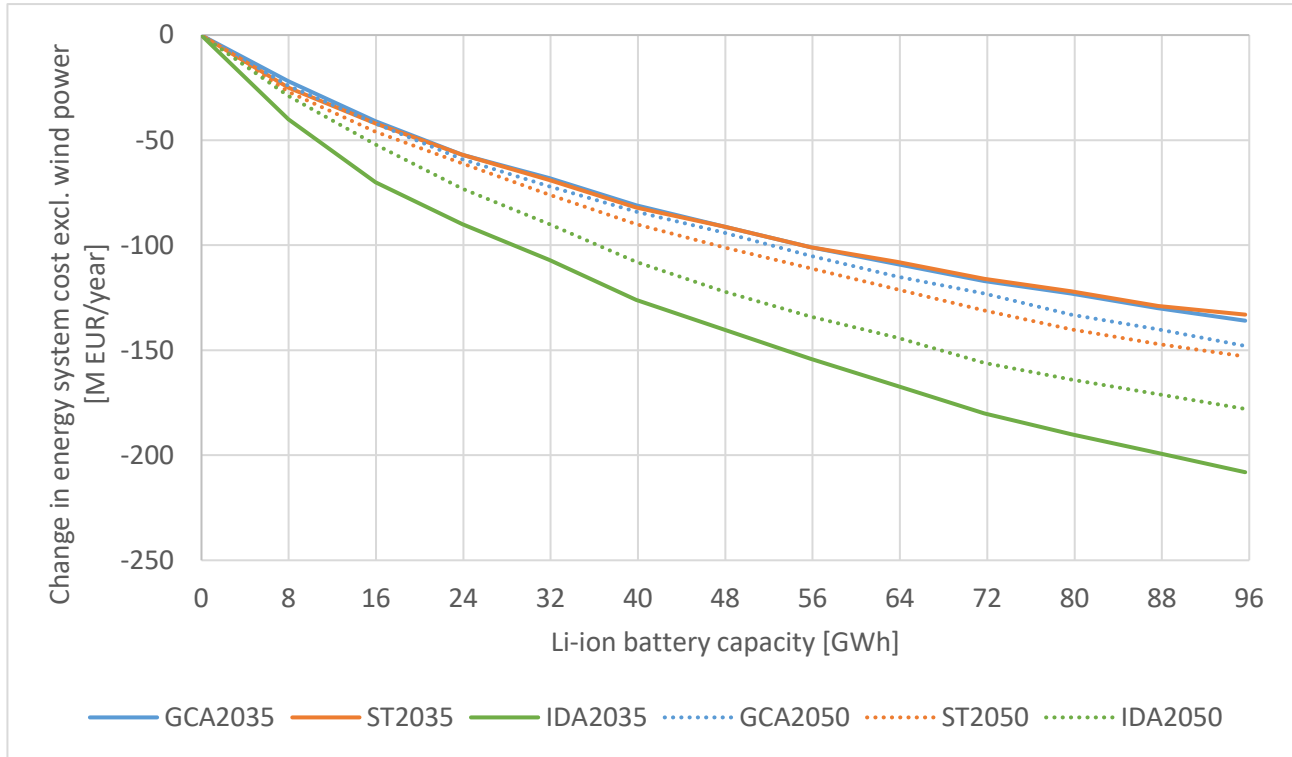


Figure 39 - The change in energy system costs, excluding wind power in each scenario at different capacities of li-ion batteries (Std. simulation).

The results in Figure 39 show that increasing the li-ion battery capacity does decrease the energy system cost. It is, however, important to remember how this result does not include the actual investment cost needed for the installed batteries, and therefore only shows the positive system benefits obtained. As described earlier, this occurs because of the uncertain future li-ion battery prices, which would otherwise dictate the results. Disregarding the cost makes it possible to assess the value provided to the system and from that discuss what a feasible future price to pay for batteries may be. The results in Figure 39 do not include the cost of offshore wind turbines as the installed capacity increases with increasing battery capacity, as was seen in Figure 33, and this investment should therefore not be subtracted from the cost savings to the system. Not including the costs for the extra offshore wind power capacity can also be seen as a best case for the grid-scale li-ion batteries.

Considering the total energy system cost, the differences observed in Figure 39 for the tested energy systems are generally minor. The differences that do occur are a result of differences in the flexibility measures and technologies already included in the systems, e.g. existing storage options, power plants, and transmission capacity. The highest benefit can be observed for the IDA2035 system, where annual savings of 29 M EUR to 75 M EUR can be obtained from installing 7.97 GWh of battery storage. In Table 6, the internal rate of return (IRR) of such an investment can be seen for a range of future battery cost estimates.

Table 6 - Internal rate of return at different li-ion battery investment cost assuming 20 year lifetime. Cost estimates from the Danish Energy Agency and Energinet [48].

Year	2020	2050	2050 (lower)	2050 (higher)
Investment [M EUR/GWh]	1,042	255	166	975
IRR 2035 (std.) - IDA2035	-16.3%	-7.6%	-4.4%	-15.9%
IRR 2035 (alt.) - ST2035	-15.1%	-6.1%	-2.7%	-14.8%
IRR 2050 (std.) - IDA2050	-18.0%	-9.8%	-6.8%	-17.6%
IRR 2050 (alt.) - ST2050	-12.7%	-2.7%	1.2%	-12.3%

The results from Table 6 represent the best-case scenario in 2035 and 2050 for both the Std. and Alt. simulation approaches. If the li-ion battery investment were to be economically beneficial, the IRR would need to be higher than the discount rate of 3% included in the models. The results in Table 6, however, show that for all price levels and scenarios except one, the IRR is negative and there would therefore not be an obvious economic incentive to invest in li-ion batteries for grid-scale storage given the assumptions of this analysis. Hence, it is likely not feasible to install grid-scale li-ion battery capacities in any of the systems if the primary purpose is solely the integration of VRE given an hourly time resolution. It is possible to increase the installed offshore wind power capacity in all scenarios without increasing the CEEP value, but since the increased VRE production increases electricity export, it is arguably not a beneficial solution. Grid-scale li-ion batteries could be useful in future renewable energy systems, but for other system benefits such as, e.g. grid balancing and frequency regulation, however, this is not investigated here, and results of this study have shown that grid-scale li-ion batteries to be inefficient at large-scale storage and integration of VRE.

5.2.3.2 High-temperature rock bed storage

High-temperature rock bed storage is only analysed in the IDA2050 scenario for several reasons. First of all, the Energinet scenarios only include a small amount of internal CHP and power plant capacity, and therefore the available steam turbine capacity is limited. In the IDA2050 scenario, it is assumed that the existing steam turbine capacity can be used to discharge the rock bed storages and produce electricity. Thus, this can be considered as a best-case scenario for implementing rock bed storage. Secondly, as high-temperature rock bed storage, and high-temperature storage in general, is an emerging technology only presently deployed on a pilot-scale it is not considered to be widely available in 2035. Therefore, the following analysis only considers rock bed storage in the context of the IDA2050 scenario. All technical and cost data for the high-temperature rock bed storages have been provided by Y. Muhammad, K. Engelbrecht, and H. L. Frandsen [49].

Table 7 shows the three different solutions for high-temperature rock bed storages investigated.

Table 7 - Rock bed storage solutions for which heat loss rates were calculated and included in energy system modelling [49].

[mm]	Insulation thickness	Concrete thickness
Scenario 1 (cheap solution)	0	400
Scenario 2 (mid-range solution)	400	400
Scenario 3 (high-end solution)	800	400

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In addition to the varying insulation rates investigated, the analysis considers two different sizes of storage with a radius of 10m and 20m respectively. This is relevant when the radius of the storage increases, so does the energy storage capacity, and the heat loss also changes depending on the size. Rock storage with a radius of 10m has a maximum storage capacity of about 1,015 MWh, while the storage with a 20m radius has a capacity of 8,000 MWh. In the ensuing modelling of the energy system in EnergyPLAN the number of installed rock bed storages are varied, starting from one and increasing to a maximum of 13. The resulting maximum tested storage capacity is therefore 13.2 GWh for the 10m radius type, and 104 GWh for the 20m radius type. Finally, the analysis considers three different charging and discharging capacities: capacities capable of charging (and discharging) the storage in 10 hours, 20 hours, and 40 hours.

Based on the assumptions listed in Table 7, the resulting heat loss for the different scenarios is illustrated in Figure 40, showing that large reductions of the heat loss rate can be expected by going from no insulation to mid-range insulation, but less so when going to the high-end solution.

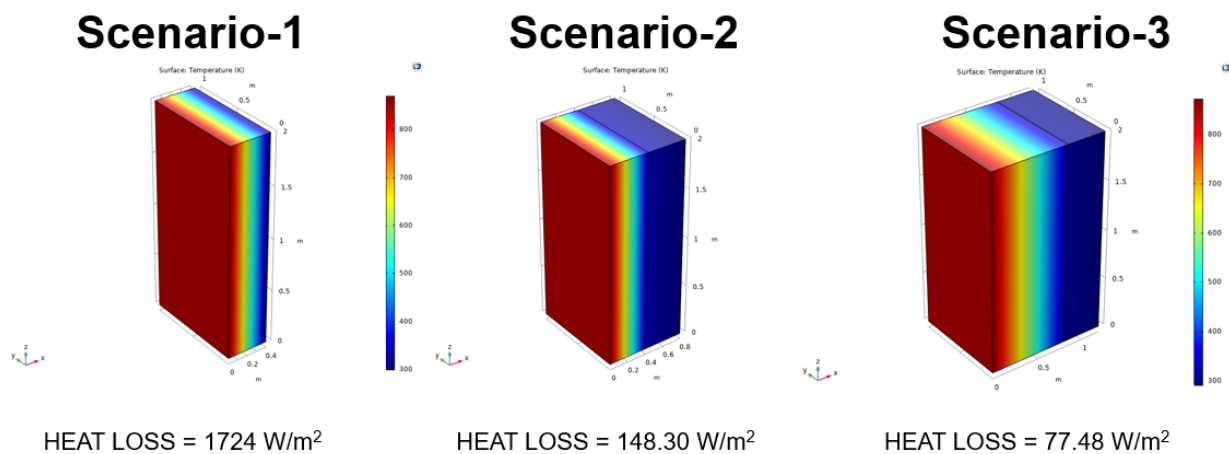


Figure 40 - Differences in insulation and resulting heat loss for scenario 1-3 (cheap, mid-range, high-end) [49].

The following costs are considered in the calculation of the rock bed storage costs:

- Cost of rocks
- Cost of insulation
- Cost of concrete
- Cost of excavation

The assumed total cost of the rock bed storage along with the heat loss rate can be seen in Figure 41, Figure 42 and Figure 43, illustrating how both the heat loss rate and the total cost of the storage depends on the insulation level and the storage size.

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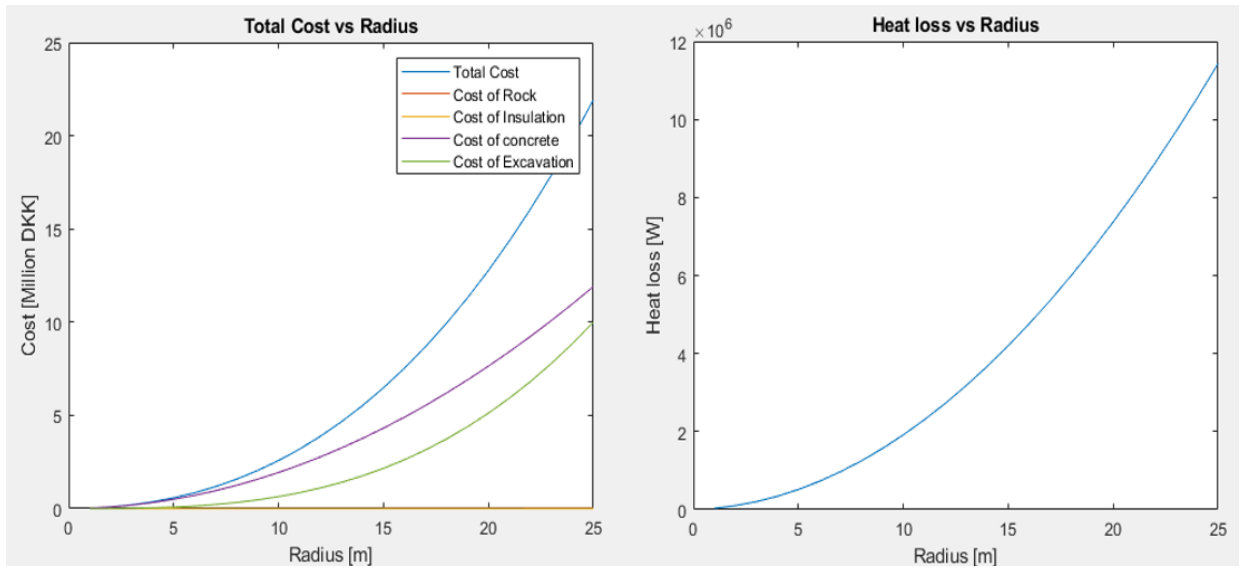


Figure 41 - Total cost and heat loss for Scenario 1 (cheap solution) [49].

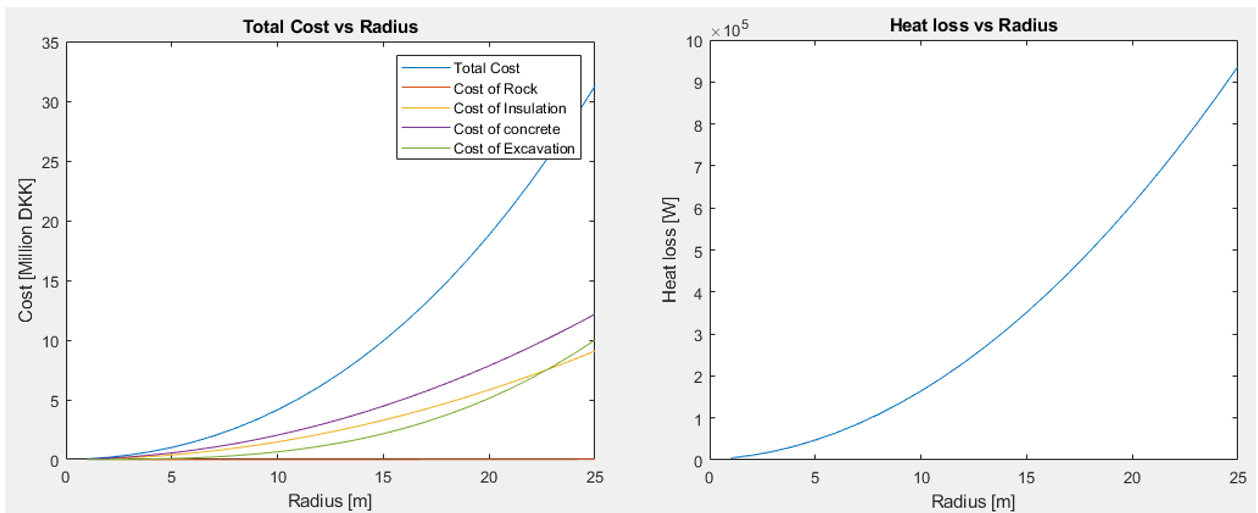


Figure 42 - Total cost and heat loss for Scenario 2 (mid-range solution) [49].

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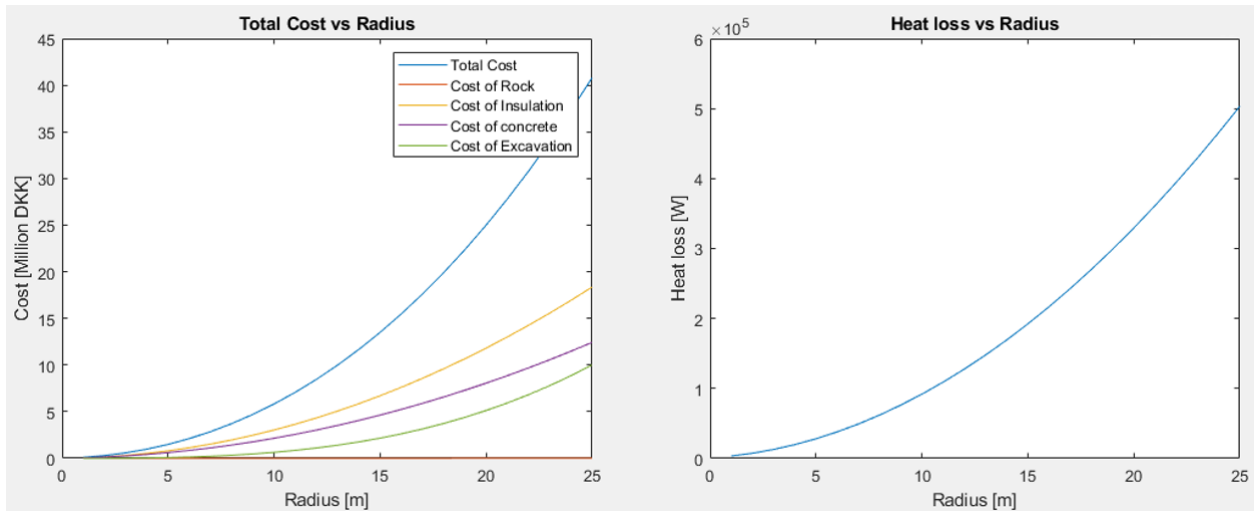


Figure 43 - Total cost and heat loss for Scenario 3 (high-end solution) [49].

In addition to the costs mentioned above for the rock bed storage, costs related to the charging and discharging of the rock bed storage, e.g. fans and heaters are included in the modelling. The cost of the heater is assumed to increase linearly with the capacity at the cost of 41,890 EUR/MW. The cost of the fans required for both charging and discharging are assumed to decrease exponentially as the capacity increases at the rate shown in eq. 1.

$$y = 47,906x^{-0458} \quad \text{Eq. 1}$$

The investment cost for the steam turbine is not included as the storages are assumed to be installed in connection to existing steam turbines. The assumptions on investment costs and efficiencies are based primarily on early-stage pilot projects and are therefore connected to significant uncertainty. The results of the following analysis, therefore, needs to be considered in light of this uncertainty, and should mainly be seen as preliminary results as rock bed storage and high-temperature thermal electricity storage, in general, are in early stages of technological development.

In Figure 44 and Figure 45, the resulting change in offshore wind power capacity can be seen for the 10m rock bed storage and the 20m rock bed storage solutions, respectively.

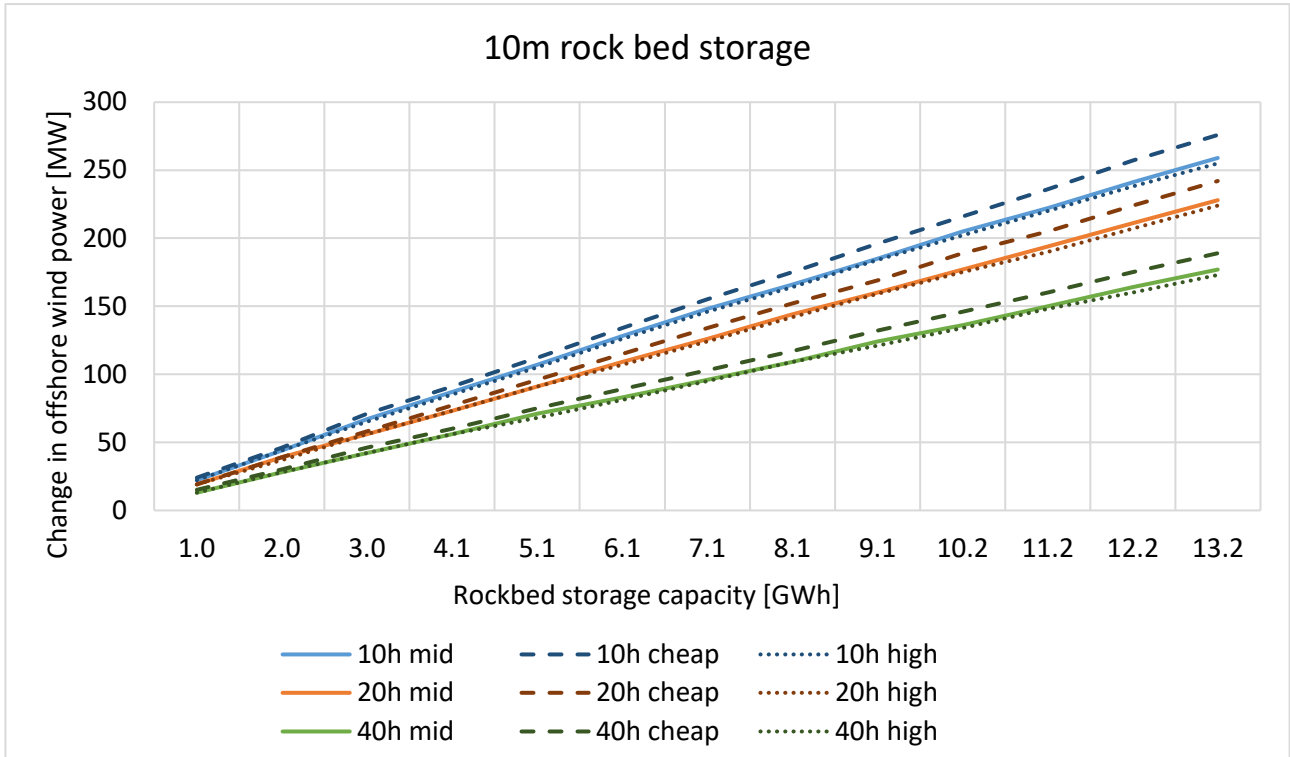


Figure 44 - The change in offshore wind power capacity in the IDA2050 scenario for different rock bed storage capacities.

For all the tested solutions, it is possible to increase the offshore wind power capacity without increasing the CEEP of the energy system. A grouping based on the charging and discharging capacity occurs, where the system with the highest charging and discharging capacity can install the most wind power. This is a likely result, as the faster charging and discharging provides more flexibility to the system and thus better enables balancing of VRE production. Differences can also be observed depending on the insulation level, but less impactful than the choice of charging and discharging capacity, as there are no intersecting points across the different insulation levels and charging capacities. A difference based on insulation level is most apparent for the cheap solution, which does not include any insulation. This is likely a result of the heat loss reduction that can be obtained going from cheap to mid-range insulation, as it was seen in Figure 40, with a much smaller difference going from mid-range to high-end insulation.

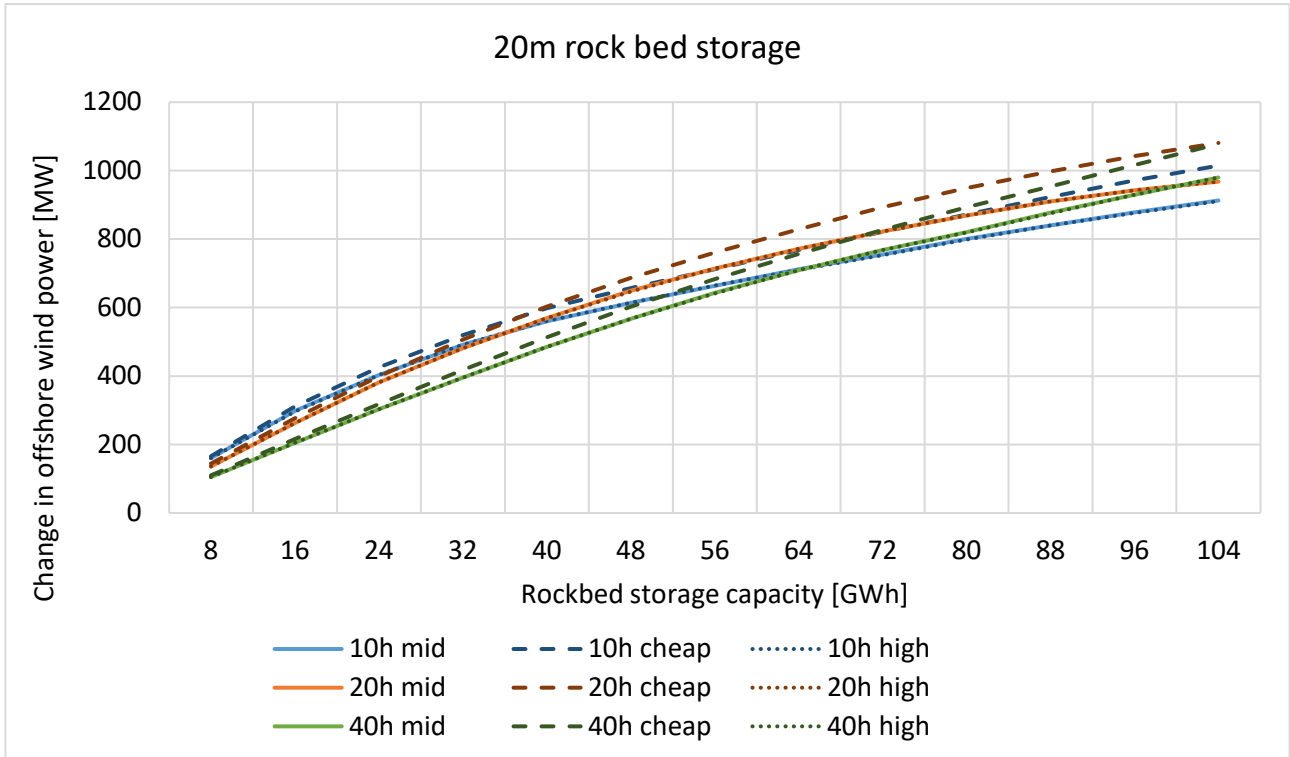


Figure 45 - The change in offshore wind power capacity in the IDA2050 scenario for different rock bed storage capacities.

Similarly, to what was observed for the 10m rock bed storage solution, the installed offshore wind power capacity can be increased without increasing CEEP in the system as the storage capacity increases. However, since the energy capacity of each store increases along with the increase in size, the total storage capacity tested is also more extensive as the number of rock bed storages included is again increased in increments of one. Because of the large storage capacities in the 20m scenario, the discharging capacity is capped in the 10h and 20h systems based on the capacity of steam turbines available in the system; therefore the results are more closely grouped in the 20m size scenarios compared to the 10m size scenarios.

In Figure 46 and Figure 47, the resulting change in biomass consumption can be seen.

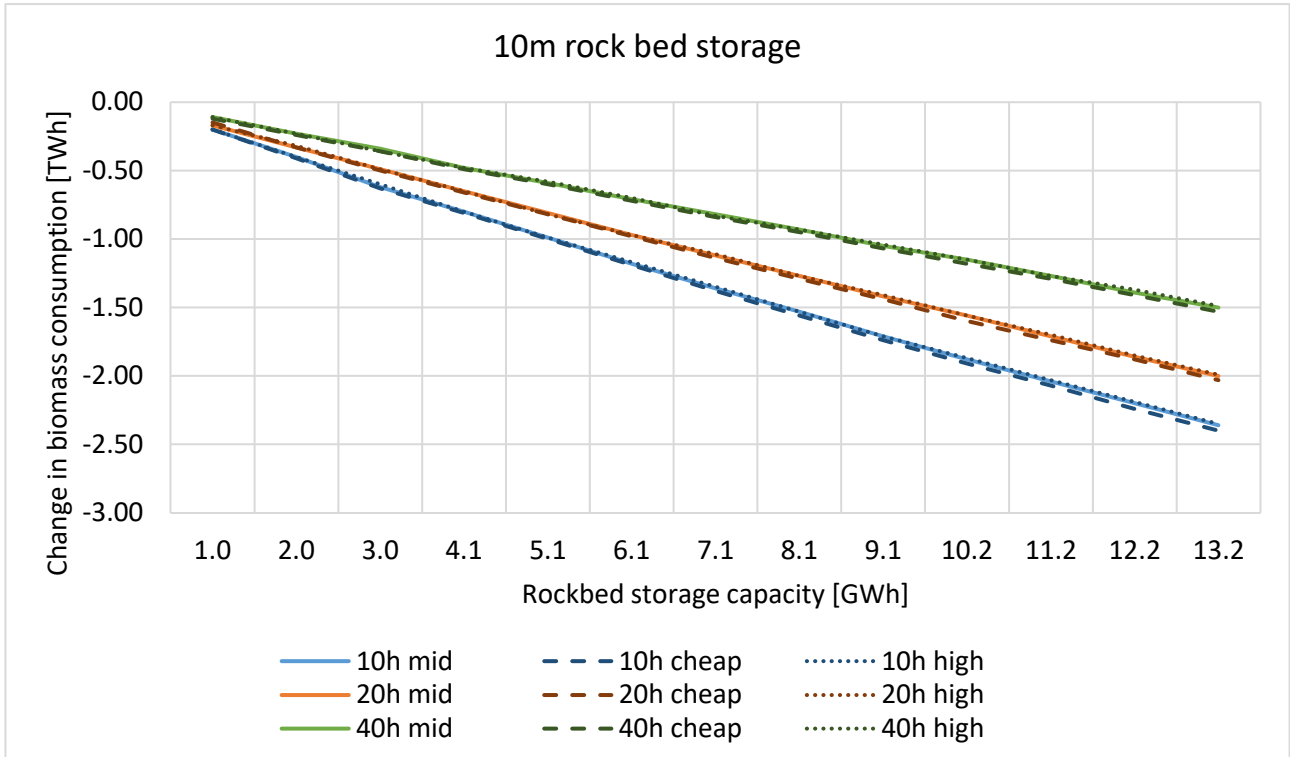


Figure 46 - The change in biomass consumption in the IDA2050 scenario for different rock bed storage capacities.

In Figure 46, it can be seen that the biomass consumption of the system decreases as the rock bed storage capacity is increased. This is mainly due to a reduced need for gas in the large CHP plants, as the plants are being supplemented by steam from the rock bed storage. Due to the reduced gas consumption, the production at gasification plants can be reduced and overall, the biomass consumption of the system.

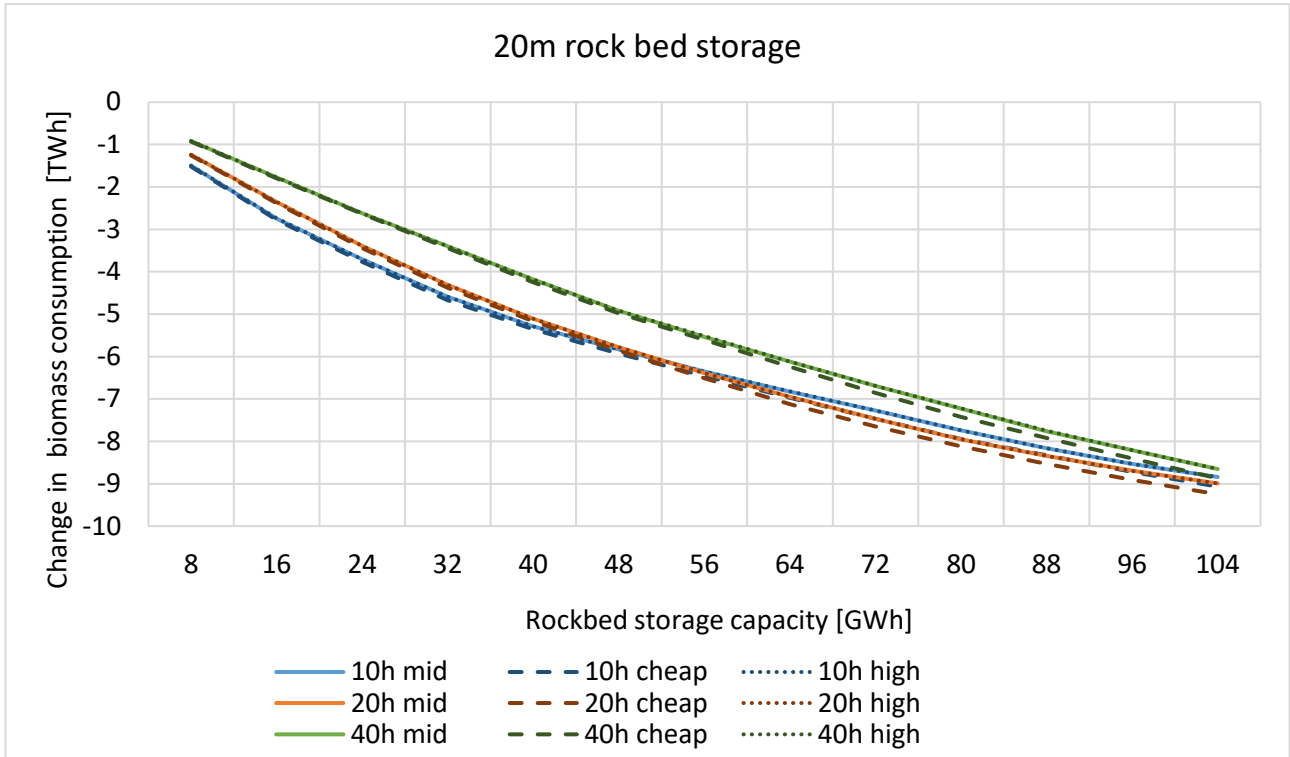


Figure 47- The change in biomass consumption in the IDA2050 scenario for different rock bed storage capacities.

The biomass consumption is also decreased as the storage capacity increases for the 20m scenario, as seen in Figure 47. Unlike the previous result for 10m storages, Figure 47 shows that at large storage capacities, the different scenarios appear to approach each other. This is due to the discharging capacity being capped for the 10h and 20h scenarios, and therefore at large storage capacities, the scenarios are only different in terms of charging capacity, which is less connected to the biomass consumption as charging is done by electricity.

In Figure 48 and Figure 49, the change in energy system cost can be seen.

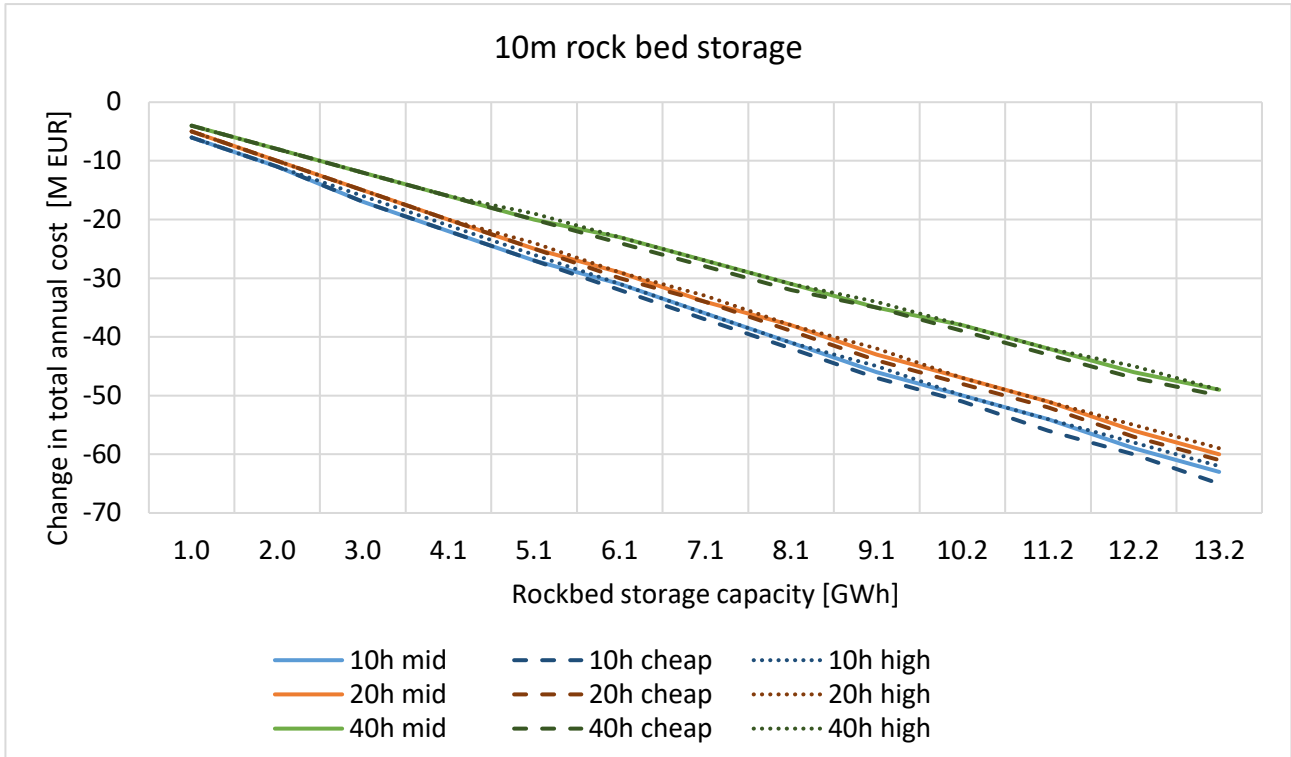


Figure 48 - The change in total annual energy system cost in the IDA2050 scenario for different rock bed storage capacities.

The results in Figure 48 indicate that including rock bed storage decreases the total energy system cost, as opposed to the results for the li-ion battery scenarios, which did not show the same economic potential. Something to consider in this context is that the results for rock bed storage rest on several critical economic and technical assumptions. This includes investment costs for the actual storage, including excavation, rocks, and insulation, and the investment cost for charging and discharging technologies, excluding steam turbine or similar. However, this does not include any costs for retrofitting existing CHP plants or similar, and it is assumed that the efficiency of the steam turbine is not affected by being partly supplied by the rock bed storage.

Similarly to what was seen for other assessment parameters, the results in Figure 48 for the 10m scenarios indicate that the charging and discharging capacity is more important than the insulation rate and that there is practically no difference between the mid-range and high-end solutions.

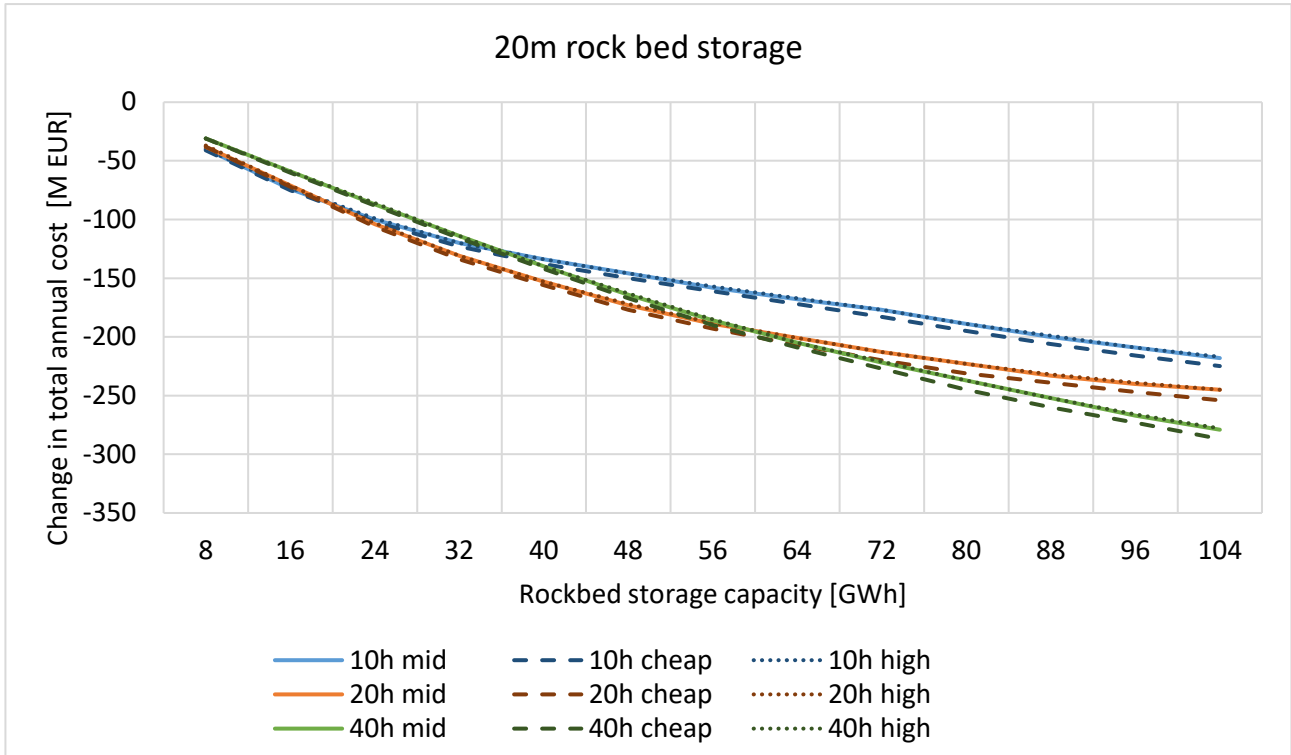


Figure 49 - The change in total annual energy system cost in the IDA2050 scenario for different rock bed storage capacities.

The insulation level is less important than the total size (volume) of the storage and the capacity for charging and discharging the storage.

At large storage capacities, the 10h and 20h rock bed storages suffer from diminishing returns from further increases to the charging and discharging capacity. This is exacerbated by the discharging capacity being capped at the existing steam turbine capacity, hence reducing the benefit obtained from further increases to the charging capacity. This results in the 40h scenario, with the smallest charging and discharging capacity, having the lowest total energy system cost at the higher end of the storage capacities tested. The savings to the energy system cost are mainly obtained from savings in fuel cost due to the reduced biomass consumption, and secondly from reduced investment in biomass gasification plants.

As previously mentioned, these results do not include investment cost for the steam turbines needed as it is assumed that the rock bed storages are installed in connection to the existing turbines at CHP plants. However, that might not be possible.

In general, across all the assessment parameters only small differences can be observed comparing the mid-range solution to the high-end solution because a large part of the heat loss can be mitigated by including at least some insulation. This is even more profound for the 20m systems, as the larger volume also helps to reduce the heat losses and therefore, the impact of increasing insulation is also reduced.

It should be noted that the analysis conducted is in many ways a best case for rock bed storage due to several of the technical and economic assumptions. It is assumed that the steam turbine capacity installed as part of the large-scale combined cycle gas turbines can be used in discharging of the rock bed storages and that this retrofit can take place without any significant expenses. Furthermore, it is assumed that the high efficiency

of the CHP plant is transferable to the rock bed storage without any decrease in efficiency from this co-firing process with steam from the rock bed storage.

It should be emphasised again that the results are not to be considered final due to the uncertainty of the input data and the modelling approach applied. There is a need for further research on high-temperature thermal electricity storages, both from a practical point of view, e.g. data from demonstration projects, but also from a modelling perspective and the level of detail such storages can be modelled at in energy system models. However, based on these initial results, high-temperature rock bed storage do show promise as a supplement to the balancing of the VRE in a future energy system, making it relevant for further studying.

5.3 Conclusions on electrification

This section summarizes the main takeaways for the analyses conducted on electrification of the energy system, the implications on future national energy system scenarios and outlines areas relevant for future research. In general, electrification will occur in all areas of the energy system, and cannot be expected to occur only in confined sectors and as isolated initiatives. Thus, this study of electrification is unable to represent all aspects and potential applications of electrification in renewable energy systems as it is a process that will occur across all sectors and technologies. Despite this apparent limitation, the results of this study do provide tangible results on the consequences of deviating from the path outlined in the references scenarios for the three areas investigated; industry electrification, demand flexibility, and electricity storage. One thing to consider when looking at the results presented in this chapter is that both the Energinet and IDA scenarios already represent highly electrified energy systems and in particular, the 2050 scenarios. Therefore, the aim of the analyses in this chapter is not strictly to argue for the relevance and need for electrification in future renewable energy systems but is also to investigate the nuances in how electrification occurs and the consequences of changing the level of electrification.

The industry sector is partly electrified in all scenarios, but especially in the Energinet scenarios, whereas the fuel distribution is more balanced across electricity, biomass, and renewable gas in the IDA scenario. The analyses on the industrial sector consider the consequences of having both a lower and higher electrification rate through both direct electrification and indirectly through increased use of hydrogen.

In both Energinet and IDA scenarios increasing the industry electrification rate of the industry sector through direct electrification (e.g. HPs) makes it possible to install an increased offshore wind power capacity. However, the economic implications of doing so depend on the system design and the technology and fuels being replaced. It is for example seen that shifting the solid biomass demand in the IDA scenario to electricity is not economically attractive, while the opposite is the case for shifting the renewable gas demand to electricity in the GCA2050 scenario, due to the replaced renewable gas being a more expensive fuel than solid biomass as it is produced through a relatively inefficient process. An analysis of indirect electrification in the form of a shift to hydrogen-based processes for high-temperature processes was also carried out. The results show that the increased use of hydrogen in the industry provides the energy system with an additional flexibility mechanism and an increase in electricity demand, which makes it possible to install a larger capacity of offshore wind power. However, there is no apparent economic benefit of doing so. Here it should be noted that, like in most other sectors, using hydrogen-based processes and technologies is still in an early development stage. Therefore, the underlying assumptions for this analysis are connected to some uncertainty, and future

research should follow up on this as the technologies mature and more specific applications for hydrogen-based processes in industry are determined.

Increasing the share of the electricity demand that is flexible within a day appears to be beneficial from an energy system perspective as it assists the integration of VRE and thus increases the potential for installing renewable technologies, while also lowering the overall system cost. However, technologies and market incentives will need to be continuously developed if the potential is to be realised as neither technologies nor market incentives are presently sufficient. All scenarios, both from IDA and Energinet, benefit from increasing the flexible electricity demand, but more so in systems with fewer other flexibility options, and in particular on the production side. Hence, the 2050 scenarios by Energinet benefitted greatly from increased flexibility, as the internal power plant and CHP plant capacity is low. Increasing the flexible electricity demand caused the systems to be less reliant on electricity import, which can be expensive in peak hours. The increase in flexibility was, to some extent, able to mitigate this, which means that savings to the system cost could be obtained. This effect was less profound in the IDA scenario, which due to a larger internal power plant and CHP plant capacity could generally avoid importing electricity during very high price periods and instead rely on internal production. Though the effects are limited due to limited capacity, as this type of flexibility only allows for demands to be moved within a relatively short period of max. a week, while flexibility for more extended periods is also needed. That said, the benefits of demand flexibility are evident from this analysis, but the actual extent of the potential and where precisely it is located remains mostly unknown. This makes it difficult to perform detailed energy system modelling, as there are many variables and unknowns to account. This is also the reason as to why the approach applied for the modelling of the flexible demand is somewhat simplified, as there is not a large amount of detailed data available. This would be an area that could benefit from further research in the future, aimed at identifying the concrete flexibility measures available along with suggestions for concrete business models and incentives aimed at realising the potential.

Based on the results of this study, li-ion batteries for grid-scale storage do not appear to be technically or economically beneficial to the energy system assuming they are installed primarily for balancing VRE fluctuations on an hourly level. This is primarily due to the significant investment associated with the batteries, where it was found that even assuming the lower boundary of 2050 price estimates batteries would not be a cost-effective solution. This does not necessarily mean that grid-scale li-ion batteries are not relevant as a technology for providing flexibility and for balancing VRE in future renewable energy systems. However, it does appear that finding primary applications beyond balancing on an hourly level will be required. This could include providing various ancillary services to the grid, e.g. in the form of frequency regulation due to the potential for providing fast-responding regulating power, or as a backup power supply for critical processes. However, other flexibility options could serve that function instead of grid-scale li-ion batteries. Some differences could be observed across the different scenarios tested for 2035 and 2050, but the general trend and conclusion is the same for all scenarios; grid-scale li-ion batteries do not appear to be relevant for balancing hourly fluctuations as tested in this analysis.

High-temperature rock bed storage did, however, show promising results. Based on the technical and economic assumptions of this study, the addition of rock bed storage was able to reduce the total system costs and support the integration of VRE. From a technical and economic standpoint, it may be most relevant in systems with existing steam turbine capacity that can be retrofitted to also function alongside rock bed storages. The modelling was only conducted for the IDA2050 scenario because it is not expected to be available

Electrification

at a commercial scale by 2030 and because the Energinet scenarios have low internal CHP plant capacity and thus limited steam turbine capacity. Hence it is not possible to make comparisons between the IDA and Energinet scenarios for this particular analysis. It does need to be underlined that the analyses carried out are in many ways a “best case” scenario and that the technical inputs and economic assumptions are uncertain due to the early stage of technological development. It will therefore be essential to continue the research and development in this area going forward as the technology matures and look to build on the results of this study in future research.

6 Heat sector

Here the heat sector is defined as including all space heating demands, hot water consumption demands, and losses in the DH systems. As such, industrial process heat demands are not included in this section.

As shown in section 2.1, in all the future scenarios, the heat demand is expected to still be a significant energy demand in the Danish energy system. The Danish heat sector is traditionally divided into DH systems and buildings with their own heat-producing technology, referred to as individual heating. As shown in section 2.1, it is expected in all the scenarios that the individual heating demand will decrease, and the DH production will stay more or less unchanged going forward. Though the ST and GCA scenarios do not detail the reasons for the decrease in individual heating production, it is assumed to be related to energy conservation efforts in the buildings and expansion of the DH systems, as the DH production does not seem to be lowered. However, it must be assumed that heat-saving efforts would not only be implemented in individually heated buildings. As the ST and GCA scenarios do not detail this, nor the expectations to the development of the heated building area in Denmark, it is not possible to clarify the resulting production numbers similarly to the IDA scenario. Hence, it is reasonable to assume that the assumptions in the ST and GCA are similar to those made for the development of the IDA scenario, where more details are available [1]. In the EnergyPLAN implementation of the ST and GCA scenarios, data from the IDA scenario has been used where no data existed for the ST and GCA scenarios. In the IDA 2050 scenario, heat savings measures result in heat savings of approximately 40.2% compared with no heat-saving measures, and the DH systems are expanded so that they supply 66% of the heat demand.

As also shown in section 2.1, there is a significant shift in the technologies used for heat production in all scenarios. Currently, individual heating production is mainly based on fuel boilers, and here all scenarios foresee a future where electric-driven HPs are the leading technology for individual heating. A shift in technologies is also seen for DH production, where CHP units are expected to not be as crucial for the production of DH in the future, and instead large electric-driven HPs, geothermal and excess heat from industrial process and electrofuel production are expected to be primary sources of DH.

6.1 Previous research

6.1.1 Heat savings

Energy conservation is essential for future energy systems since this ultimately reduces the need for energy resources, thereby lowering the costs of the system. It is therefore essential that new buildings live up to efficient building standards which ensure a low energy demand for heating. When it comes to the existing buildings, however, heat savings through retrofitting and refurbishment play a key role, since most existing buildings will still be standing for several decades. However, if the heat savings are to be feasible, they must not be more costly than it is to produce the heating they save. In [50], Lund et al. (2014) analyze to which extent heat savings should be implemented, and to which extent it is more feasible to merely produce the needed heating, rather than investing in heat savings. The paper addresses the Danish building stock development towards 2050 and analyses the feasibility of performing heat savings on existing buildings and new buildings. The results showed that for existing buildings, which account for the largest part of the building

stock in 2050, heat savings are highly feasible if they are implemented as a part of the ongoing renovation of the buildings, whereas they are not feasible if implemented on their own.

In [51], Thellufsen and Lund (2015) argue that energy savings are essential measures for renewable energy systems. However, they demonstrated that energy savings are system dependant and that it is crucial to understand this dependency, as well as to be able to study this system dependency using an appropriate tool, which includes all sectors. The analysis of the article shows, that if energy savings are implemented for both electricity and heating in the Danish energy system, synergy effects are obtained, since the combined savings are more significant, than if implemented in the sectors individually. Furthermore, the article shows that savings in the electricity sector have a higher impact on the primary energy supply reductions than savings in DH do.

In the analysis, heat savings are implemented in an otherwise fixed energy system, meaning that changes are only done in the DH demands and the electricity demand, while the other facets of the system are left unchanged. This is useful when testing how energy savings perform in an existing system. However, the article does not consider that when the demands change, the requirement for energy production capacities also changes, since energy savings typically lower the peak demands. Therefore, when modelling future energy systems, such as Denmark in 2050, this is important to consider as well.

In 2016, Mathiesen et al. [52] analyzed how the building sector should develop towards the year 2050 in order for it to support the vision of a cost-effective, sustainable energy system. They found that existing buildings should save around 40% in heating and domestic hot water, decreasing their energy demand from 132 kWh/m²/year in 2015 to approximately 80 kWh/m²/year in 2050. Furthermore, new buildings should use about 55 kWh/m²/year.

6.1.2 Type of heating supply

Lund and Mathiesen [53] analysed in 2015 what effect different types of large-scale CHP plants have in the overall Danish energy system in 2050 with 100% renewable energy. For this analysis, an existing 100% renewable energy system scenario for Denmark was used. The energy scenario used was the 2050 recommended scenario from the research project CEESA (Coherent Energy and Environmental System Analysis) from 2011 where EnergyPLAN was used for the energy system analyses where all energy conversions and energy sectors were included [54]. The different large-scale CHP technologies that were analysed were Combined cycle gas turbine (CCGT), Circulating Fluidised Bed (CFB) steam turbine, and Advanced Pulverised Fuel (APF) steam turbine. The analysis found that CCGT provided the lowest energy system costs, with CFB a close second. However, CCGT also provided the lowest biomass consumption, and in the analyses, it is argued that it is essential to keep the biomass consumption low, as not to put a strain on the biomass consumption globally, as more countries go towards increasing amounts of RES. The study found that CCGT was the technology best suited for central CHP plants in future renewable energy systems. These results were also analysed and discussed concerning the investigation of potentials of transforming the Copenhagen energy system to 100% renewable energy in 2050 [55].

In 2012, Mathiesen, Lund and Connolly [56] analysed different solutions in the heating sector effect on the biomass consumption of the energy system in future 100% renewable energy systems. This was analysed

using three different 100% renewable energy system scenarios with different levels of wind power and consequently, different levels of biomass consumption. The scenarios were from the research project CEESA (Coherent Energy and Environmental System Analysis) from 2011, where EnergyPLAN was used for the energy system analyses where all energy sectors were included [54]. For individual heating it was analysed what the effects of changing 21% of the end-use heat energy demand to different technologies, being; biomass boilers, HP's, electric heating and micro fuel cell CHP based on biogas or hydrogen/synthetic gas, as well as the effect of connecting this individual heating demand to DH systems instead. The analysis found that connecting this demand to DH would provide the lowest energy system costs. Similar energy system costs were found using electric heating, which was followed by HPs that provided the third lowest energy system costs. Besides showing the lowest energy system costs, connecting the individual heating to DH also showed the lowest biomass consumption of all the analysed technologies, with HPs with solar thermal having the second-lowest biomass consumption. The micro fuel cell CHP provided the highest energy system costs as well as the highest biomass consumptions. These conclusions were independent of the scenario used. Mathiesen, Lund and Connolly [56] also analysed the effect of using different energy conversion technologies in the DH. The technology changes tested were; only using centralised boilers, solar thermal covering 11% of the DH production, 1,200 MW_e large-scale HPs, 2.65 TWh industrial excess heat, 11.1 TWh heat from waste incineration in either boilers or CHP, and waste incineration CHP with absorption HPs connected to geothermal. This analysis found that only using biomass boilers for DH increased both the biomass consumption and energy system costs significantly. Using large-scale HPs reduced the biomass consumption regardless of the amount of wind power in the system, though at low levels of wind power large-scale HPs increased the energy system costs. The implementation of solar thermal and geothermal reduced the biomass consumption but increased the energy system costs. Industrial excess heat and waste incineration reduced biomass consumption and energy system costs, though for waste incineration the reduction were larger with CHP rather than boiler.

Sveinbjörnsson et al. [57] investigated different types of distributed energy storage technologies in order to identify which could be technically and economically beneficial for the integration of RES. For the study, an adapted baseline energy model for Germany for 2010 was used. The modelling was done in EnergyPLAN. Several different energy system configuration scenarios were then developed based on the model, and different electric, heat, and gas storages, as well as conversion and interconnectors, were tested in the different energy system configuration scenarios. The different technologies were compared based on the energy system costs, the CO₂ emissions, and how much energy the storage or conversion technology discharged to the energy system. This was done at different levels of wind power and PV electricity production. The study also found that individual HPs were feasible in all the energy system configurations. Heat storages were found to be feasible regardless of energy system configuration potentially, but the benefits of heat storages were found to increase when connected with a P2H technology, such as HPs. In addition, the heat storages and energy conversion technologies in DH showed lower costs than when used in individual heating, and these also showed more flexibility in DH than when used for individual heating.

In 2020, Ea Energianalyse [58] analysed the possibilities and challenges related to significant electrification of Danish energy consumption. The analyses were done in the energy system optimization tool Balmorel, where the electricity exchange between different European countries is included in the analyses. The model can make some investment decisions based on the assumed costs. The analysis simulates the energy system

in 2020, 2030, 2040 and 2050 under two different degrees of electrification, being; one based on the European Commissions “In-depth analysis in support of the Commission’s communication COM(2018) 77” from 2018 [59] (namely COMBO), and one with more ambitious electrification of the Danish energy demands (here-named Ambitious). Concerning the heat demand in buildings, the COMBO scenario assumed 74% electrification and the Ambitious scenario assumed 88%, with the difference being that the COMBO scenario had more heat demand in buildings being supplied by biomass and P2X technologies, where the Ambitious scenario included more HPs. The study concluded that individual heated buildings should be connected to DH, or in case of not being able to connect to DH, electric-driven HPs or a hybrid HPs should be used. Despite this, in the Ambitious scenario, the study found that the Danish DH demand would decrease to around 30 TWh in 2050 due to the connected buildings becoming more energy efficient. The DH production in the Ambitious scenario was in 2050 found to be mainly delivered by surplus heat from P2X technologies, electric-driven HPs and biomass-fired units. In order to use these heat sources most efficiently in the Ambitious scenario, the model invested significantly in seasonal heat storages in the DH systems, so that the seasonal heat storage capacity in DH went from less than 0.5 PJ in 2020 to around 5 PJ in 2050. The study found that DH can have an important role going forward, as it enables the utilization of excess heat from P2X technologies and can provide flexible electricity demand due to HPs and large heat storages. The study also found that the Ambitious scenario reduced the total costs of the energy system in both 2040 and 2050, whereas it increased the costs in 2030, compared to the COMBO scenario. The cost savings occurred primarily due to reduced investments in electrofuel production technologies, a more cost-efficient transport sector, and a cost-efficient industry sector.

In 2012, Hedegaard et al. [60] used a scenario for the Danish energy system in 2020 with 50% wind power in the electricity supply to analyze the potential of using individual HPs alongside different individual heat storage technologies for integrating wind power into the Danish energy system. The scenario was modelled in EnergyPLAN. The study found that the most critical step was to replace individual fuel boilers with individual HPs. Including different storage options alongside the individual HPs could also reduce the excess electricity production and reduce the fuel consumption of the energy system. However, of the different heat storage technologies only passive heat storage, where the building mass was used for heat storage by adjusting the indoor temperature, was found to be cost-efficient.

6.2 Analyses

6.2.1 Heat savings

This section analyses the feasibility of implementing heat savings in existing buildings. Furthermore, this section analyses the impact that heat savings have on the remaining energy system in terms of primary energy consumption and biomass consumption.

This study uses the same cost curve for heat savings as was used in IDA’s Energy Vision 2050 to study the effect of implementing different levels of heat savings, developed in [50]. The cost curve expresses the marginal cost of improving the energy performance of existing buildings, under the assumption that these buildings will be refurbished anyway due to regular wear and tear. Therefore, the curve only includes the cost for materials and labour used directly for improving the energy performance of buildings. See [50] for more details.

Heat sector

The reference year of the cost curve is 2010, in which the heat demand of existing buildings was identified as 131.8 kWh/m². In IDA2050, heat savings corresponding to approximately 40.2% were recommended, corresponding to a recommended heat demand of 78.8 kWh/m², at the cost of 32,590 M EUR. This is the starting point of the analysis. Subsequently, in steps of 2%-points, the heat demand for individual heating and DH is increased and decreased compared to the IDA2050 level, while for each step, several related input parameters are adjusted as well, to reflect the changes performed. The methodology is summarised in Table 8, and the results are presented in Figure 50.

Table 8 – Input parameters adjusted in the analysis (left column) and their description (left column).

EnergyPLAN input	Description of how the input is adjusted
Heat demand per household	Increased and decreased in steps of 2%
Heat production from individual boilers and individual HPs	Increased and decreased in steps of 2%
Heat from individual solar thermal	Increased and decreased in steps of 2%
DH demands in group 2 and 3	Increased and decreased in steps of 2%
Peak load boiler capacity in DH	Adjusted to 1.2x peak DH demand
HP capacity in DH	Increased and decreased in steps of 2%
Geothermal in DH	Increased and decreased in steps of 2%
Investment cost for heat savings	Identified from the cost curve developed in [50]
Investment for DH grid	The investment costs for expanding the DH share of the total heating from 53% in 2015 to 66% in IDA2050 is adjusted according to the relative increase or decrease in the heating demand. This assumes that with more or less savings, the grids will have to transport less or more heat respectively, and the dimensioning of the grid and the related costs reflects this.
Distributions for individual heating and DH demand	For each step, these distribution curves are adjusted, to reflect the changing demand in space heating, while maintaining the same demand for domestic hot water. Here, the summer period demand profile is assumed to represent the domestic hot water demand year-round.

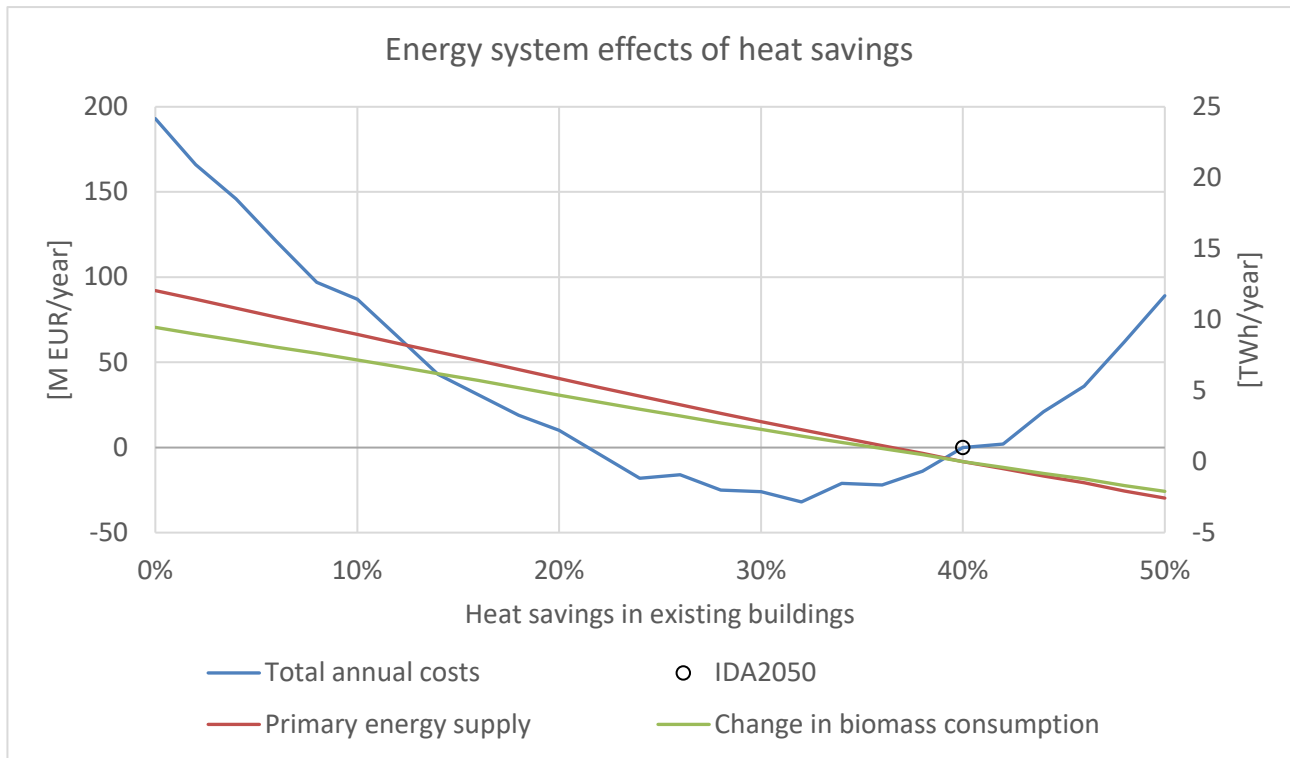


Figure 50 – Change in total annual costs, biomass consumption and Primary energy supply when implementing different levels of heat savings compared to the original IDA2050.

Figure 50 shows how the total annual costs of the energy system vary if different levels of heat savings are implemented in the IDA2050 scenario. Although heat savings are costly, the figure shows that it is even more costly to refrain from investing in them. If no heat savings are implemented, the total annual costs of the system are the highest of the tested scenarios, approximately 200 M EUR more expensive than with the savings utilised in IDA2050. Implementing heat savings reduces the total annual costs significantly, and at approximately 32% savings, the cost optimal level of savings is found, considering only the total annual cost. After this point, the costs start to increase again, first gradually and eventually more steeply. This is due to the applied cost curve for heat savings, which assumes that the most cost-efficient renovations are implemented first.

Although the cheapest level of heat savings is approximately 32%, the figure also shows that the biomass consumption continues to decrease as more heat savings are implemented. With limited biomass resources available, this supports the argument of implementing slightly more savings than the cost optimal 32%. The reduction in biomass consumption is mainly due to reduced consumption for DH fuel boilers where the biomass consumption decreases from 6.27 TWh at 0% savings down to 0.84 TWh at 50% savings and biomass gasification that sees a decrease from 53.60 TWh at 0% savings down to 48.38 TWh at 50% savings. Individual biomass boilers only account for a relatively small end-use demand and see a reduction in biomass consumption from 2.04 TWh at 0% savings to 1.16 TWh at 50% savings.

6.2.2 Individual heating solution

This section deals with individual heating solutions. As shown in Table 9, the individual heating solutions in the different scenarios are primarily based on a mix of individual biomass boilers and individual electric-

driven HPs. In some scenarios, the production from these technologies is supplemented by solar thermal. The individual heat demand not covered by these technologies are supplied by direct electric heating and gas boilers.

Table 9 – Share of individual heat demand supplied by this technology group, the efficiencies of individual biomass boilers, the COP of individual HPs, and the solar thermal share used alongside these two technologies in % of the heat demands.

	Individual biomass boilers			Individual electric-driven HPs		
	Share of individual heat demand	Efficiency	Solar thermal share	Share of individual heat demand	COP	Solar thermal share
ST2035	43.9%	89.0%	0.0%	24.4%	3.28	0.0%
GCA2035	33.3%	89.0%	0.0%	48.7%	3.12	4.9%
IDA2035	10.0%	90.9%	15.9%	90.0%	4.36	15.2%
ST2050	16.6%	89.0%	0.0%	80.2%	3.14	12.1%
GCA2050	16.6%	89.0%	0.0%	80.2%	3.14	12.0%
IDA2050	9.9%	90.9%	17.4%	90.1%	4.53	15.3%

As also seen in Table 9, the individual heat demand in all the 2050 scenarios is primarily by electric-driven HPs supplemented by solar thermal. Due to the high reliance on electric-driven individual HPs in the scenarios, it is relevant to investigate what the energy system effects are of not having these. In the 2050 scenarios, the second most used individual heat technology in all scenarios is biomass boilers.

In the public discussion about individual heating, another potential solution is highlighted, namely gas-driven absorption HPs. These units would allow for more efficient use of gas for household heating compared with traditional gas boilers. Using gas instead of electricity could allow for using the gas grid for heating purposes instead of having to expand the electricity grid locally to allow for electric-driven HPs. However, in a 2050 scenario where all fuel usage must be renewable, the gas used for heating must be produced in some renewable way. As the gas usage in all scenarios already exceeds the potential for biogas, including hydrogenation of the CO₂ content of that biogas, the gas must come from another source, with the most apparent source being biomass gasification. However, this would, in turn, increase the biomass consumption of the system. E.g. if not including electricity use for biomass gasification or increase in excess heat from biomass gasification, then in the GCA2050 scenario, where the biomass gasification efficiency is 76% and the average gas-driven power plant efficiency is 40.4%, the biomass consumption used for electric-driven individual HPs would only be larger than a gas-driven HP with a COP of 1.7 [62] if around 75% of the electricity for the electric-driven HP is from power plant production. This seems unrealistic as the CHP and power plants only make up a small percentage of the total electricity production, as shown in section 2.1. If looking at the IDA2050 scenario, where the biomass gasification has an efficiency of 83% and the power plants an efficiency of 61.5%, then gas-fired HPs will always increase the biomass consumption, even if the power plants produced all the electricity. Cost-wise it is also questionable whether gas-driven HPs would result in any real system advantage. With a discount rate of 3% the yearly costs excluding fuel or electricity for the gas-driven absorption HPs in 2050 is around 970 EUR/unit (based on data from [62] assuming 50% air-to-water and 50% ground source) and the electric driven HP is around 681 EUR/year using the same assumptions. Based on these considerations, mainly the increase in biomass consumption, gas-driven absorption HPs for individual heating is not investigated further in this.

Heat sector

First the effect of having biomass boilers for individual heat demand instead of electric-driven individual HPs is investigated. This is done by gradually reducing the demand supplied by HPs while at the same time increasing the demand supplied by individual biomass boilers, as to keep the individual end-user heat demand constant. This is done until only 5% of the installed HP supply initially is still being supplied by individual HPs. The different scenarios have different amounts of individual heat demand supplied by electric-driven HPs, and as such, whereas the percentage change will be the same in each, the total energy amounts differs. The share of solar thermal shown in Table 9 is kept constant for each of the two technologies.

When adjusting the individual heat demand, the offshore wind power capacity has been adjusted as well. The reasoning is that the offshore wind power sizing in each scenario has been mainly based on the total electricity demands of the scenarios. As the electricity demand is reduced when changing individual electric-driven HPs to biomass boilers, the offshore wind power capacity needs to be readjusted. This has been done in EnergyPLAN by ensuring that the amount of CEEP without transmission lines is the same. The change in offshore wind power capacity when the individual HP capacity is reduced can be seen for the basic fuel price level and an international electricity market price of 47 EUR/MWh in Figure 51.

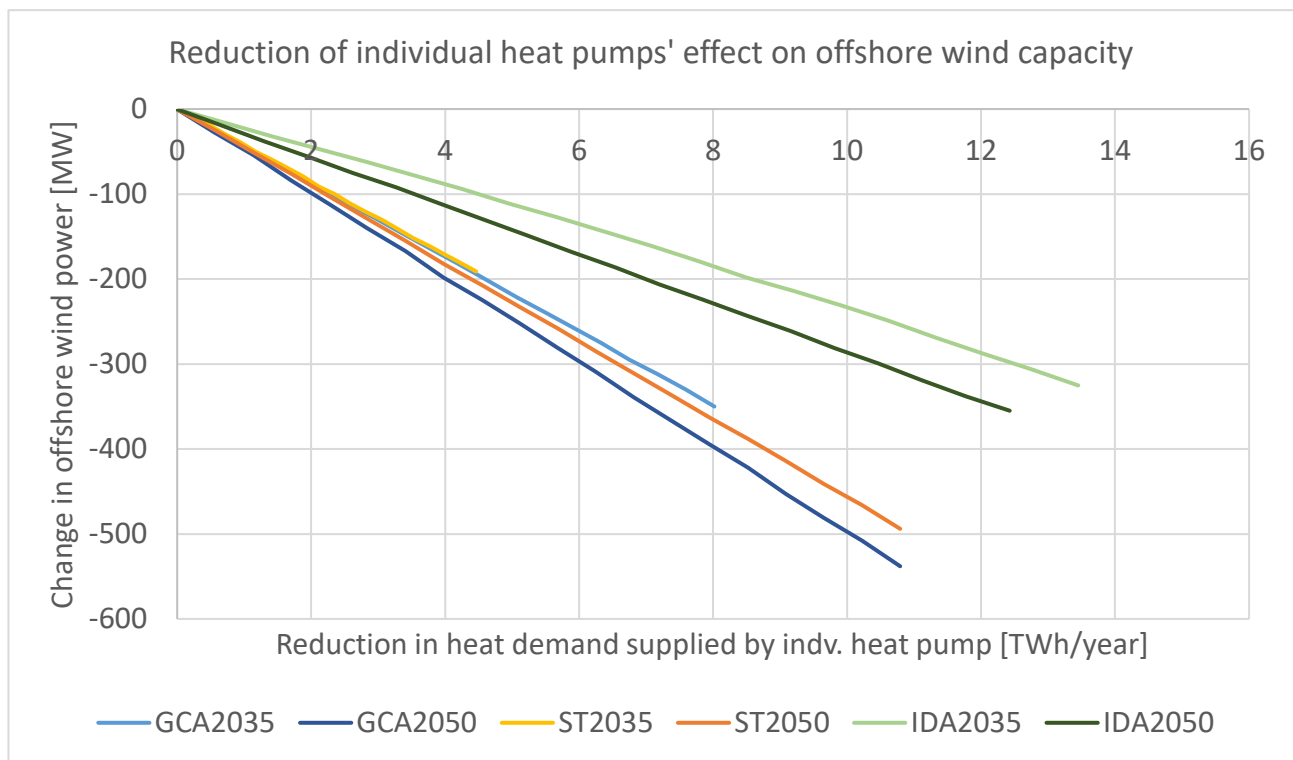


Figure 51 – The change in offshore wind power capacity made in each scenario at the different levels of reduced heat demand supplied by individual electric-driven HPs at the basic fuel price level and an international electricity market price of 47 EUR/MWh.

Figure 52 and Figure 53 shows the results with the changed offshore wind power capacity shown in Figure 51. Each scenario has for each of this level of changes been simulated using the different three fuel price levels as well as the 16, 47, and 77 EUR/MWh electricity price levels. As such, for each step of change, nine different market price situations have been tested. As such, the results in Figure 52 and Figure 53 are presented as intervals, showing the maximum effect and minimum effect.

Figure 52 shows the effect on the energy systems' biomass consumption when changing from individual HPs to individual biomass boilers. The biomass consumption includes both that directly related to the individual biomass boilers but also changes to biomass consumption in other parts of the energy system, such as biomass consumption for power plants.

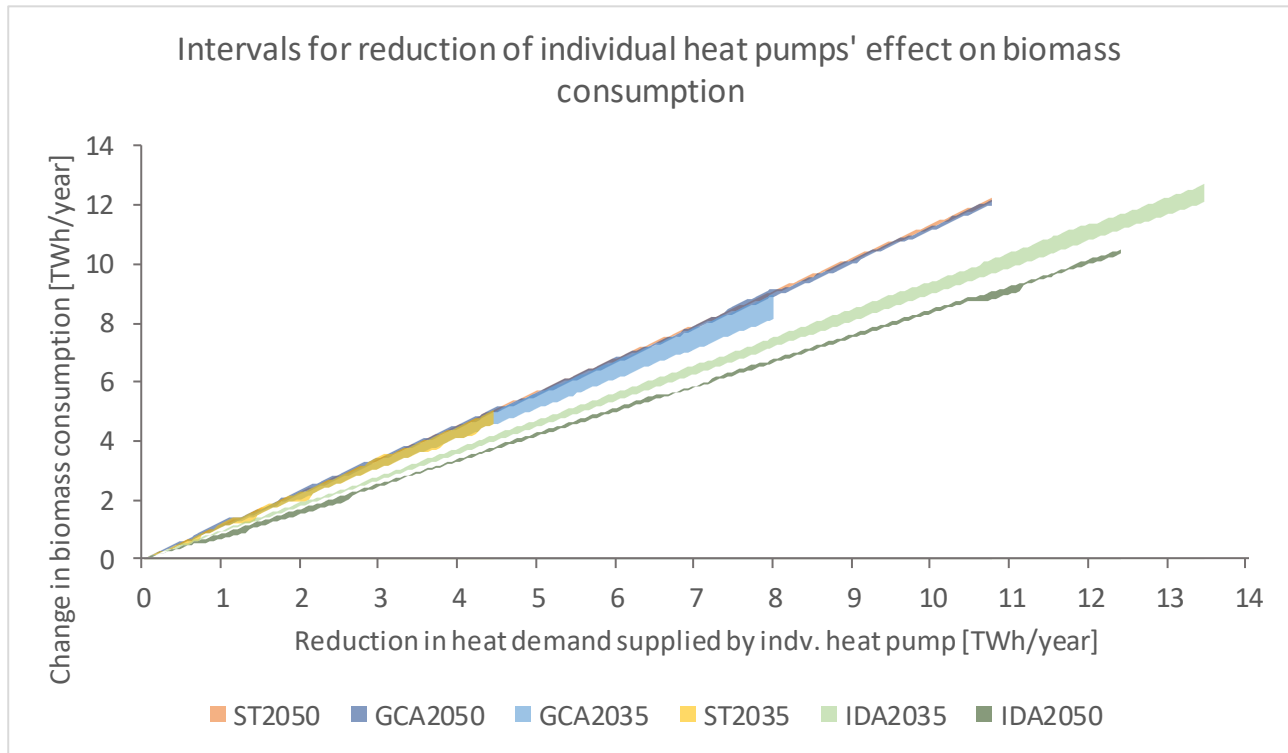


Figure 52 – Change in biomass consumption in Denmark when changing from individual HPs to biomass boilers in each scenario.

As can be seen in Figure 52, the effect on the biomass consumption is similar in all scenarios, indicating that the effects on the other parts of the energy system of this change are minor in all scenarios. The lowest effect on the biomass consumption is found in IDA2050 and IDA2035, and the most significant effect is found in ST2050 and GCA2050 scenarios. As seen in Table 9, the IDA scenarios utilize more efficient technologies, as well as more solar thermal. As the IDA scenarios have more solar thermal in connection to biomass boilers, and slightly more efficient biomass boilers, then the increase in biomass consumption when having more biomass boilers is reduced, as the solar thermal share is kept constant.

Also, changing the market prices do not seem to affect this conclusion, as the biomass consumption intervals for all scenarios are relatively narrow. The most considerable effect of different market prices is found in the 2035 scenarios, with ST2035 and GCA2035 showing the most extensive spread. The reason for the larger effect of different market prices in 2035 is due to having more biomass-fired CHP and power plants than the 2050 scenarios, and as the demand for electricity decrease, the power plants are operating less, which in turn reduces the effect on the biomass consumption of changing to individual biomass boilers. This effect is larger in the fuel price situations where the power plant is operating more due to having a competitive bidding price on the electricity market. As such, the steepest increase in biomass consumption can be seen at the low external electricity market price levels. This effect is lower in the 2050 scenarios, as in IDA2050 the CHP and power plants are highly efficient gas-fired CCGT units, and in the ST2050 and GCA2050 scenarios the

CHP and power plant capacities are significantly lower than in the other scenarios as these scenarios are more reliant on import and export of electricity. The potential use of biomass to produce electricity in other countries is not included in the biomass consumption shown in Figure 2, as this only shows the biomass consumption in Denmark.

Figure 53 shows the effects on the total annual energy system costs.

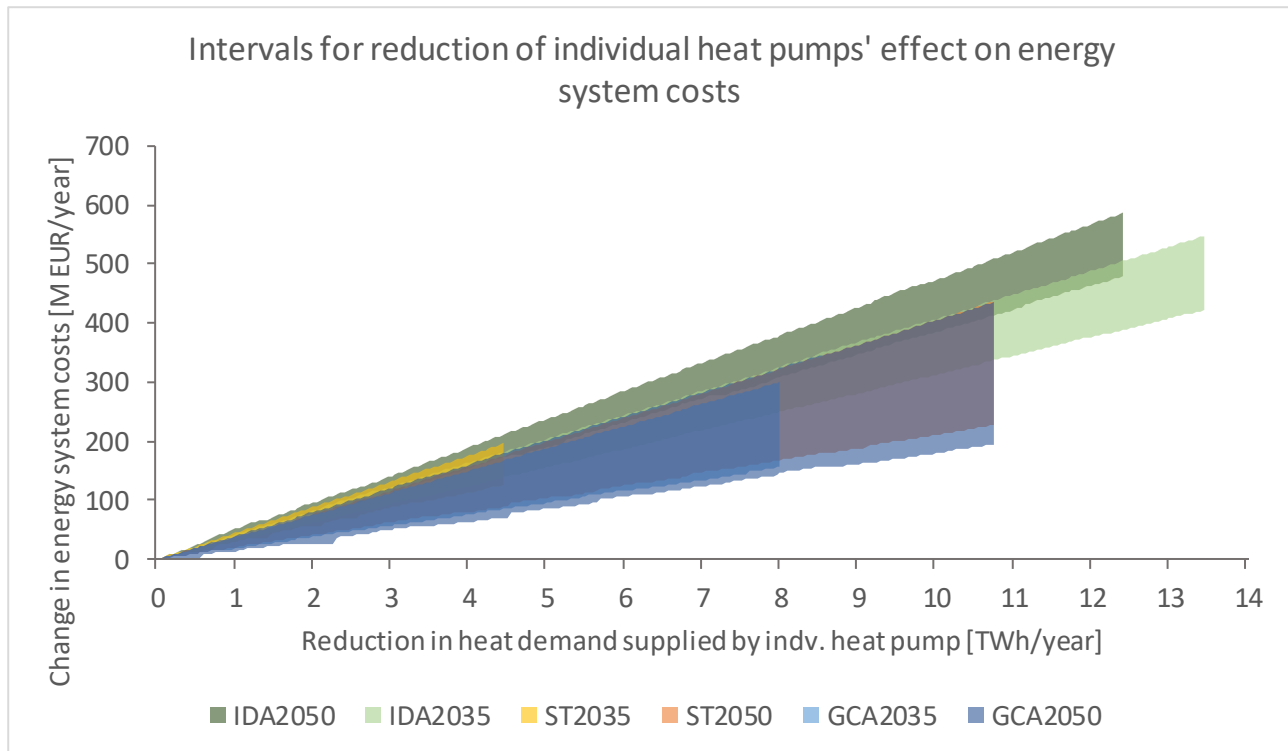


Figure 53 - Change in total annual energy system costs when changing from individual HPs to biomass boilers in each scenario.

As seen in Figure 53, in all scenarios, the change from individual HPs to biomass boilers increases the total annual energy system costs. The cost increases are due to increases in the variable costs and fixed OM costs. The increases in variable costs are mostly related to increased use of biomass, as shown in Figure 52, though the effect of this is reduced somewhat by the decrease in electricity demand, as this reduces the need for import of electricity and electricity production on CHP and power plants in Denmark. However, the total increase in cost for biomass is larger than the decrease in electricity-related costs, even at the high electricity market price level. The total fixed OM costs of the energy system are increased by the biomass boilers having higher fixed OM costs than HPs and reduced a bit by the reduction in offshore wind power capacity at decreasing levels of individual HPs. However, the increase in fixed OM for individual biomass boilers is more significant than the reduction that is gained by the decrease in offshore wind power capacity. Where the variable costs and fixed OM costs of the energy system in totals increases at decreasing levels of individual HPs, the total investment costs of the energy systems decrease. The reason is that the investment cost for the biomass boilers is set to 6.5 M EUR/1000 units in 2035 and 5.9 M EUR/1000 units in 2050, and the HPs are set to 8 M EUR/1000 units in 2035 and 7 M EUR/1000 units in 2050. In the GCA2035, ST2050 and GCA2050 scenarios, the effect on the investment costs are slightly reduced as here there are no solar thermal in connection with biomass boilers, as is the case for the individual HPs, as shown in Table 9. Likewise, the reduction

in offshore wind power capacity at reduced levels of individual HPs reduces the total investment costs of the energy system, though the effect of this is lower than the effect of the direct investment costs in the individual heating technologies.

It can also be seen in Figure 53 that the increases in costs are most extensive in the IDA scenarios, which is due to the higher COP of the individual HPs in the IDA scenarios, which is also why the most considerable effect can be seen in IDA2050, as the COP is highest in this scenario, as shown in Table 9. The results for the IDA scenarios are also not to a large extent affected by changes in market prices for fuel and electricity. Especially the effect of changing electricity market prices has minimal effect on the results for the IDA scenarios, which again is due to the high COP of the HPs in the IDA scenarios. As such, the spread of total annual costs for the IDA scenarios shown in Figure 53 is mainly due to the different fuel market price levels, and as such, the total annual cost results for the IDA scenarios is mostly related to the biomass costs.

The effect of different market prices is most significant for the ST and GCA scenarios. This is primarily due to the variations in the external electricity market prices, as these scenarios have less installed CHP and power plant capacity than the IDA scenarios. Instead, the ST and GCA scenarios have larger installed transmission capacity, and as such, the results for these are more affected by changing electricity market prices, as the electricity for the HPs to a greater extent than for the other scenarios are affected by the cost of import and export of electricity. For these scenarios, the largest increase in cost is at the high fuel price level and the electricity market price of 16 EUR/MWh, as here the biomass boilers are the most expensive to operate, and the electric-driven HPs are the least costly to operate.

6.2.2.1 *Individual heat storages*

As shown in Hedegaard et al. [60], different storage options alongside individual HPs could reduce the CEEP and reduce the fuel consumption of the energy system. However, the study also found that only passive heat storage, where the building mass was used for heat storage by adjusting the indoor temperature, reduces the total annual costs of the energy system. It is therefore relevant to investigate the effect of individual heat storages in the different energy scenarios. Individual heat storages serve different purposes, some are installed in order to ensure that hot water consumption can be met at peak loads, some are used to increase utilization of solar thermal, and some are installed in order to ensure a specific operation of the heating solution, such as the operation of a HP. As shown in Table 9, in all scenarios, except ST2035, solar thermal is installed in connection to individual HPs. The different scenarios do not detail the type of individual heat storage utilized, nor the costs are explicitly defined. For the ST and GCA scenarios, the actual installed capacity is not known. However, in the implementation of the ST and GCA scenarios into EnergyPLAN, the individual heat storages are set to be sufficiently large to utilize all the solar thermal energy produced. As such, the individual heat storage capacity in the ST and GCA scenarios is expected to be on the low end, as individual heat storage capacity for the individual HPs and the potential to utilize passive heat storage is not considered. However, the installed heat storage can be utilized by both the solar thermal and the individual HPs in the EnergyPLAN simulations. The IDA scenario is developed in EnergyPLAN, and as such a capacity for the individual heat storages is included in the EnergyPLAN models, however, the actual type of individual heat storage is not clarified in the background report. The IDA scenario's individual heat storage capacity is also the least amount of storage needed in order to utilize the installed solar thermal energy, indicating that a similar method is utilized as for the implementation of the ST and GCA scenarios into EnergyPLAN. Though the same principle method is used, there is a significant difference in the size of the heat storages, as the total heat

demand for individual HPs and the share of solar thermal differs for the different scenarios. In the IDA2050 scenario, the heat storage capacity installed at buildings with individual HPs is set to be equal to 1 average day of heat demand resulting in a total energy storage capacity at these of 35.7 GWh, corresponding to 2.73 GWh storage capacity per TWh heating demand. For the ST2050 and GCA2050 scenarios, this is set to 0.22 average days of heat demand resulting in a total of 6.8 GWh, corresponding to 0.6 GWh storage capacity per TWh heat demand.

As such, the installed capacity of individual heat storages varies significantly between the different scenarios, both in totals but also relative to the heat demand, and there is significant uncertainty in relation to the type and cost of the installed individual heat storage. As such, here, the effect of changing the individual heat storage capacity at the buildings with individual HPs is analyzed without changing the investment costs of the individual heating solutions.

Figure 54 shows the change in total annual costs for the energy system at different levels of individual heat storages at the buildings heated by individual HPs. The x-axis shows the storage size as an average day of heat demand, meaning that the total capacities are not the same, though the sizing is similar for the same demands. The starting value for the storage size is 0.1 for GCA2035, 0 for ST2035, 0.22 for GCA2050 and ST2050, and both IDA scenarios, it is 1.

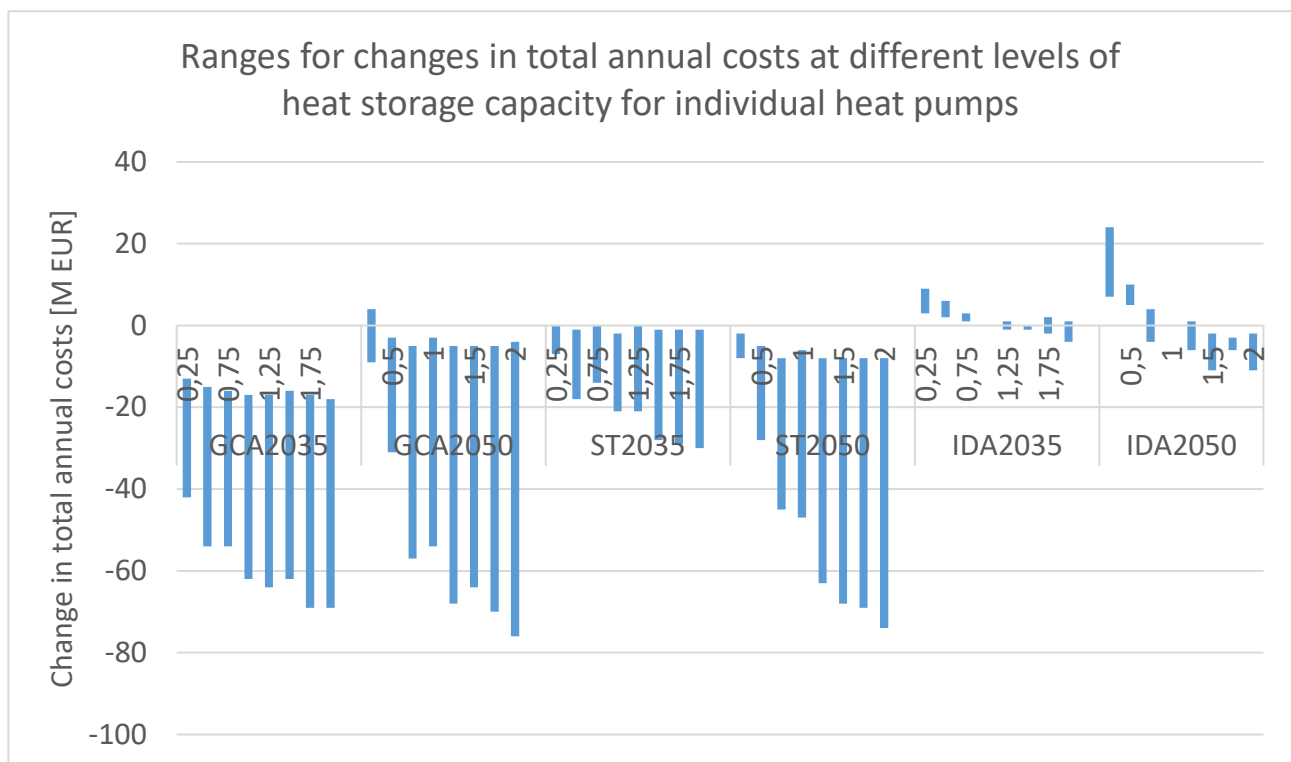


Figure 54 – Ranges for changes in total annual costs at different levels of heat storage capacity for individual HPs. Capacity in days of average heat demand.

As shown in Figure 54, the total annual costs of the energy system are reduced until the storage reaches a specific size; afterwards, additional reductions are depending on the price level used. This size of the storage needs to be to fully utilise the solar thermal capacity installed, which for all corresponds to the starting value. The benefits are most considerable with a high price level on the external electricity market, as the higher

market price level also includes larger absolute differences in the hourly market prices, meaning that the cost-benefit of consuming electricity flexible is larger in the high electricity price levels, which a larger storage capacity allows. Also shown in Figure 54 is that the market price levels mostly affects the change in total annual costs for the ST and GCA scenarios, whereas the IDA scenario results are less affected by the market price levels. This is due to the higher amount of internal dispatchable electricity generation and more flexible electricity consuming units, especially electrolysis, in IDA which reduces the effect of external market prices on the prices internal in the modelled energy system.

Going to biomass consumption, Figure 55 shows the ranges for changes in yearly biomass consumption.

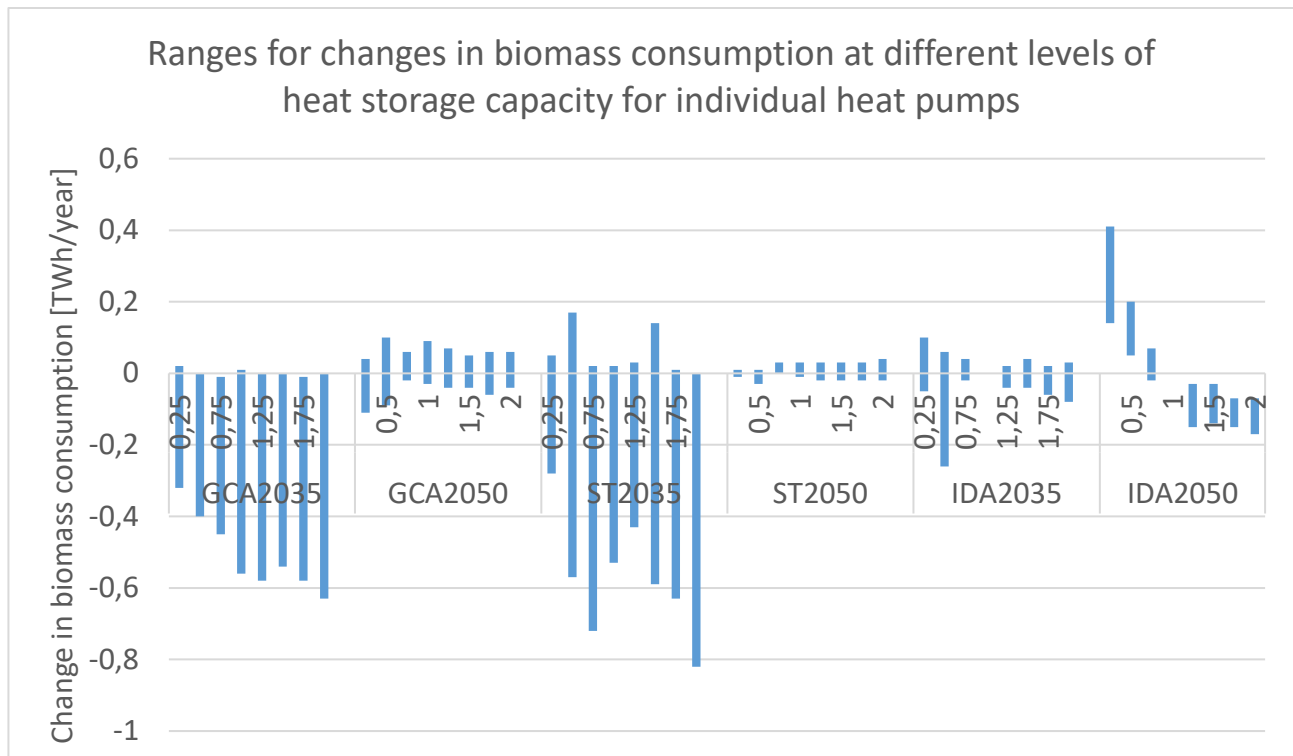


Figure 55 - Ranges for changes in biomass consumption at different levels of heat storage capacity for individual HPs. Capacity in days of average heat demand.

As shown in Figure 55, larger individual heat storages generally reduce the biomass consumption of the energy system. However, the effect of this is limited in GCA2050 and ST2050 as these have little internal biomass consumption for electricity production, and as such, potential flexibility gains in these scenarios mostly affect the import and export of electricity.

6.2.2.2 Conclusions on the individual heating solutions

- If biomass boilers are used instead of electric-driven HPs for individual heating, both the biomass consumption and the total annual cost of the energy system increases. This is regardless of the analysed energy system scenario as well as the market prices for fuel and electricity.
- Having solar thermal in connection with individual biomass boilers reduce this increase in biomass consumption, though not significantly.

- There is uncertainty related to the actual change in total annual cost is in all scenarios, depending on the cost of biomass. In scenarios that are reliant on the international electricity market prices, the international electricity market price also affects this increase in total annual costs.
- Individual heat storages in connection with electric-driven HPs and solar thermal can reduce the total annual costs (not including costs of the individual storages) and biomass consumption of the energy system but only up to a certain point, depending on the amount of other flexible electricity demands and variations in electricity market prices.

6.2.3 District heating

DH is used for a large share of the total end-user heat demand in all the modelled scenarios. However, the production of DH varies depending on the scenario. Figure 56 shows the production of DH in each of the different scenarios, as the production is simulated in EnergyPLAN.

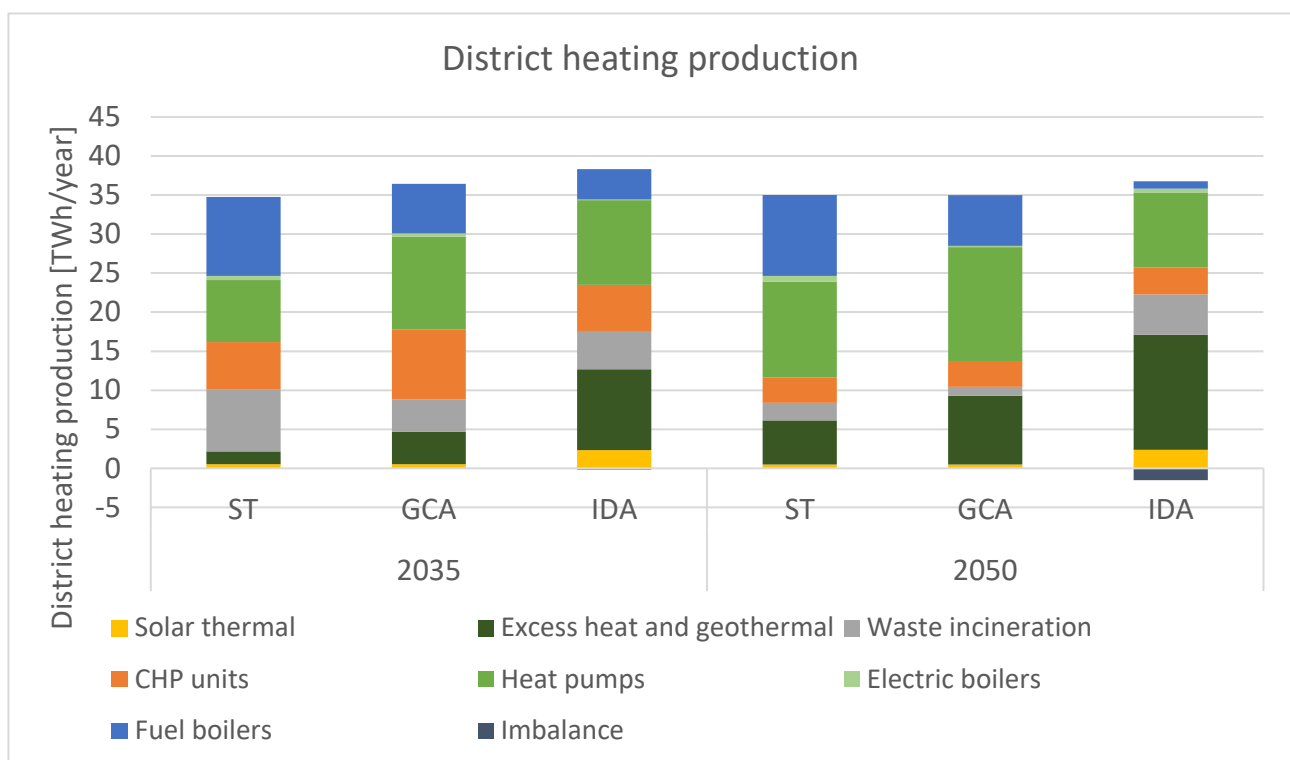


Figure 56 – DH production in the different scenarios, as modelled in EnergyPLAN.

As shown in Figure 56, the total production of DH is similar in all scenarios. Previous research found that HPs for DH is a cost-effective way of integrating VRE into the DH, and in the scenarios HPs are also extensively used, with the GCA2050 scenario having the most massive production of DH via HPs of the scenarios, followed by the ST2050 and GCA2035. Historically DH has shown to be beneficial for the energy system by being able to collect otherwise discarded heat and distributing it to end-users. This excess heat has both been concerning excess heat from the industrial process as well as from electricity production. Excess heat and geothermal are mainly used in the IDA scenario, where the excess heat to a large extent is a by-product of the electrofuel production, which is larger in the IDA scenario than in the ST and GCA scenarios. All scenarios include CHP units; however, it is clear that in all scenarios the DH produced by CHP is reduced in 2050 compared with 2035, as especially HPs and excess heat are used to a larger extent in 2050.

Based on the used technologies and the previous research, it is found that it is relevant to investigate:

- The role of CHP units for DH production using the IDA scenario
- HPs using the ST and GCA scenarios
- Heat storages using all scenarios

6.2.3.1 Combined heat and power for district heating production

There is a significant difference between the different scenarios concerning the CHP capacity installed, and the type of CHP technology utilised. The IDA scenarios have the largest installed CHP and power plant capacity with more than 5.5 GW_e in 2035 and 6 GW_e in 2050, where 4.5 GW_e is large-scale in both. The capacity of CHP and power plants in the ST2050 and GCA2050 is 2.1 GW_e which mostly is small-scale units with only 0.5 GW_e being large-scale units. The ST and GCA scenarios are instead based on a change from internal dispatchable units to being more reliant on import and export of electricity, meaning that these two scenarios also foresee a large expansion of the transmission grid from around 6.5 GW in 2020 [63] to 10.4 GW in ST2050 and 12.7 GW in GCA2050. In IDA2050 this capacity is 7.1 GW.

A discussion in the current Danish energy system is what kind of CHP technology, if any, is most relevant when going towards 100% renewable energy. This is investigated in this using only the IDA2050 scenario as this scenario has the largest reliance on CHP and power plants in Denmark, meaning that the effects of different CHP and power plant technologies are most prominent in this scenario. First, three different large-scale CHP technologies are evaluated, and afterwards, the value of CHP of each technology is evaluated. The three technologies evaluated are:

- Gas turbine, combined cycle, extraction plant (CCGT)
- Large Wood Pellets CHP, 800 MW feed, Extraction (Woodpellet)
- Gas turbine, simple cycle (large), back pressure (SCGT)

The technologies are described in detail in [64]. The parameters that have been changed in the scenarios are shown in Table 10.

Table 10 – Overview of input parameters for the three different types of central CHP plants [64]

	Condensing eff.	CHP electric eff.	CHP heat eff.	Investment [M EUR/MW-e]	Yearly fixed OM [% of inv.]	Lifetime [Years]
CCGT	61.5%	52%	39%	0.80	3.25	25
Wood pellet	43.7%	35%	65%	1.90	2.58	25
SCGT	44.0%	44%	44%	0.52	3.46	25

Each of these is implemented so that the total CHP condensing capacity remains unchanged. In IDA2050 the total condensing CHP capacity is 4.5 GW, where CCGT is the only used technology for large-scale CHP. The difference between condensing and CHP electric efficiencies is used to set the capacity for the CHP part of the units.

As the simulation strategy used is based on a market approach, the change of the CHP unit also affects the exchange of electricity with the surrounding countries, as the different technologies have different electricity production costs. This is, however, important when comparing the biomass consumption of each technology,

as a technology with low electricity production costs will operate more to sell electricity to surrounding countries than more expensive technology. As such, Figure 57 shows the biomass consumption and net export of electricity for the three technologies at the 15 different market price levels. To better show the result, a linear trendline has been added for each technology.

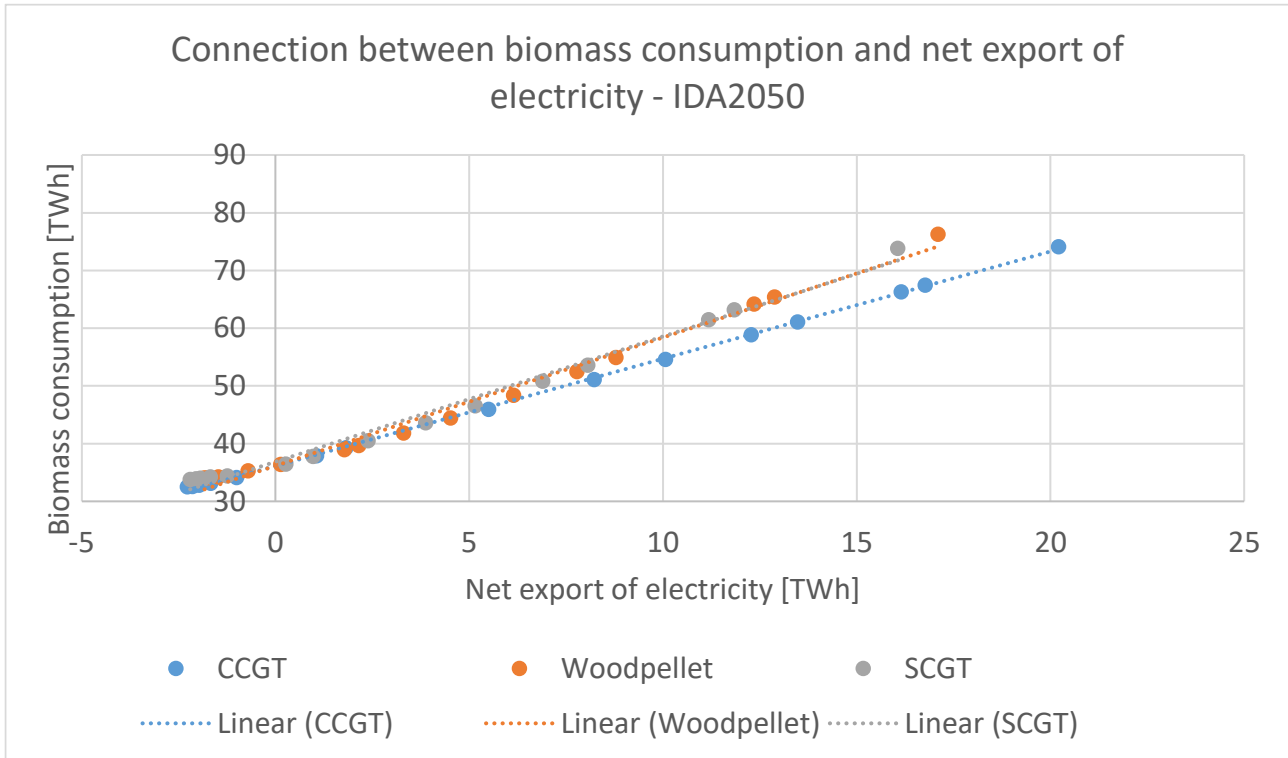


Figure 57 – Plot of biomass consumption and net export of electricity for the three different technologies under 15 different market price levels (3 different fuel price levels and five different electricity price levels). Dotted lines are linear trendlines for each technology.

As shown in Figure 57, the CCGT generally results in a lower biomass consumption at the same levels of net export of electricity, whereas Woodpellet and SCGT CHP plants show similar tendencies. Besides the efficiency of the CCGT itself, the biomass consumption for this unit, as well as the SCGT, is dependent on the efficiency of biomass gasification, as the biomass consumption is increased with increased gas consumption in order to adhere to a yearly net gas exchange of zero. As this unit is still in development, there is some uncertainty concerning the future efficiency and role of this technology. Likewise, due to the bi-product from this process, biochar, there are discussions on whether biomass gasification only should be developed for high gas efficiency, or whether a lower gas efficiency would allow for increased production of biochar for agricultural purposes would be more beneficial [65], [66]. The scenario is operated again with low efficiency for biomass gasification equal to the current 2015 efficiency, meaning a reduction from 83% to 75% [67]. Figure 58 shows the results similar to Figure 57; however, in Figure 58, a lower biomass gasification efficiency is used.

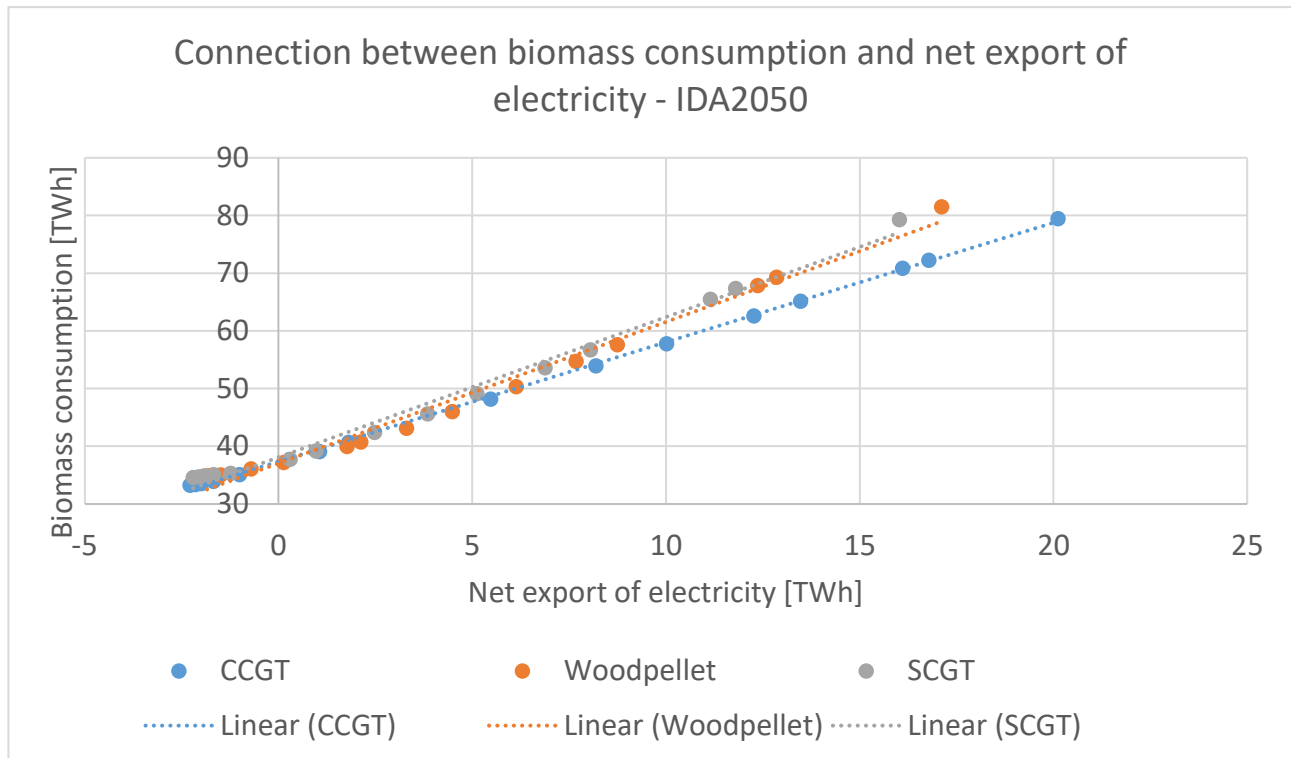


Figure 58 - Plot of biomass consumption and net export of electricity for the three different technologies under 15 different market price levels (3 different fuel price levels and five different electricity price levels). Dotted lines are linear trendlines for each technology. Reduced efficiency of gasification

As seen in Figure 58, the conclusion is not changed with the lower biomass gasification efficiency, being that the CCGT provides the lowest biomass consumption for the system at the same levels of net export of electricity. Though, the difference between the CCGT and the two other technologies are decreased. Again, the Woodpellet and SCGT plants show similar results, though SCGT now increases the biomass consumption of the system more than the Woodpellet CHP, although the difference between the two is minimal.

From a total annual cost perspective, the CCGT is the reference solution, as this is the technology utilised in IDA2050, and the changes in total annual costs are thereby in relation to using the CCGT. Replacing the CCGT with Woodpellet CHP increases the total annual costs of the IDA2050 scenario by 357-492 M EUR, depending on the cost assumptions, where an electricity price level around 47 EUR/MWh result in the lowest increase in costs due to the operational strategy of the Woodpellet CHP. With reduced biomass gasifier efficiency, the range instead 339-498 M EUR. The total annual cost results for SCGT is not as clear, as the range here is an increase in total annual costs of -68 to 107 M EUR and with reduced biomass gasifier efficiency the range is -73 to 109 M EUR. The SCGT reduces the total annual costs of the energy system compared with CCGT at the electricity price levels 16, 31 and 47 EUR/MWh, mainly as the operation of the CHP and power plants are lowest at these electricity price levels, meaning that the reduced investment cost of the SCGT makes up for the reduced efficiency compared with the CCGT. This conclusion is unaffected by the fuel price levels, though higher fuel prices reduce the gain of the SCGT in total annual costs.

6.2.3.2 No CHP

Another discussion in relation to large-scale CHP units is what benefit the system have from the heat produced by these. The reason for this discussion is the reduced production of the CHP units in a future energy system with large shares of VRE, as shown in section 2.1. Also, other low marginal cost DH producing technologies, e.g. HPs and excess heat from other processes, are extensively utilised, reducing the need for the heat provided by CHP units. Similarly to the previous part, in this part, CHP units effects on the biomass consumption of the energy system is analysed. This is done by removing large-scale CHP units and replacing them with pure power plants, while small-scale CHP plants and baseload operating CHP plants are kept unchanged. Again, the three technologies shown in Table 10 are used.

Figure 59 shows the change in biomass consumption concerning the change in the net export of electricity. Each dot represents a price scenario for the given technology in the IDA2050 scenario, and the change is in relation to the variant where large-scale CHP Units are still in the scenario. The offshore wind power capacity is adjusted as described in section 3.4, which results in an increase of 67-83 MW for CCGT with CHP capacity, 35-51 MW for Woodpellet option, and 46-77 MW for SCGT. The removal of CHP units allows for more use of HPs and electric boiler in the DH systems, which in turn allows for a larger amount of offshore wind power to be integrated without increasing the CEEP of the energy system.

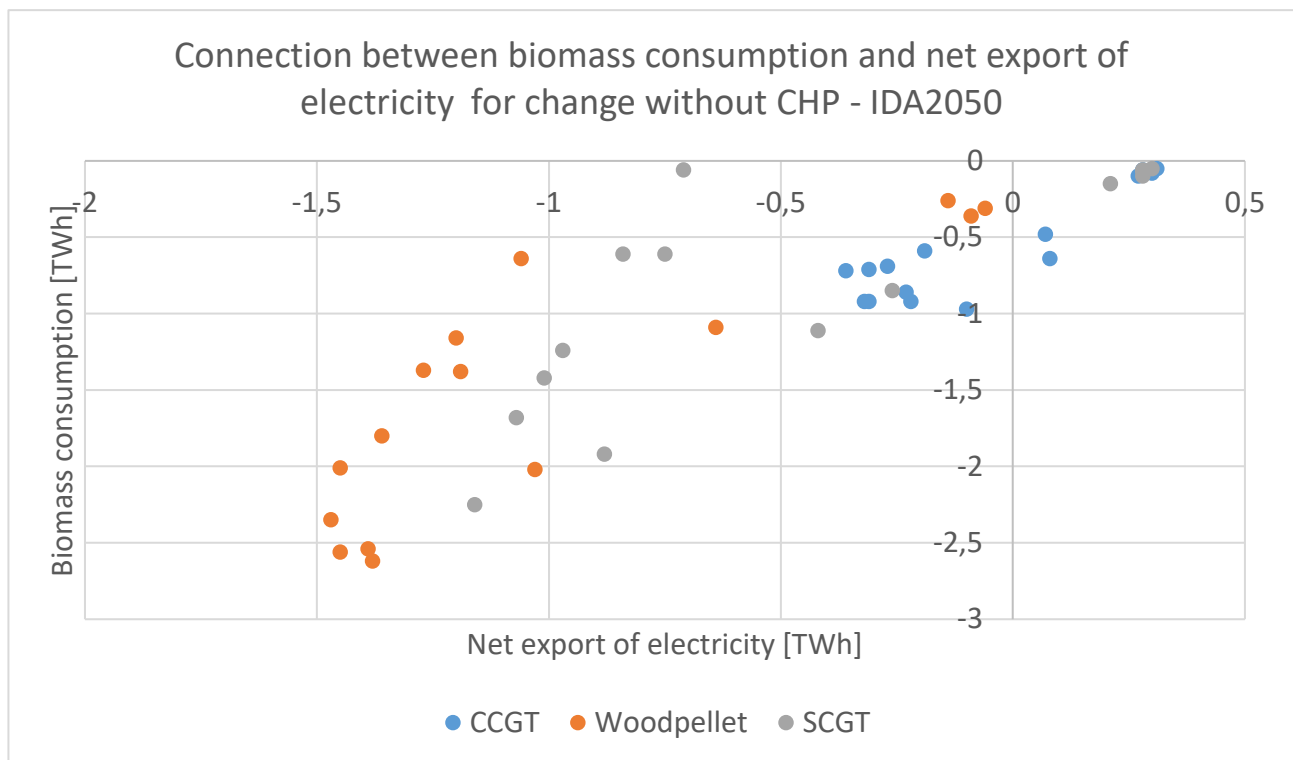


Figure 59 - Plot of change in biomass consumption and change in a net export of electricity for the three different technologies under 15 different market price levels (3 different fuel price levels and five different electricity price levels). The change is in relation to the variant with large-scale CHP units.

As shown in Figure 59, changing from large-scale CHP capacity to power plant capacity reduces the net electricity export in most cases, which is due to fewer hours of operation of the large-scale units as the marginal operational cost increases when the heat output cannot be sold. The reason for the few cases of SCGT and

CCGT having a higher net electricity export is due to the increased offshore wind power capacity, and the cases with increased net export are for high electricity market price levels where the operation of the large thermal units is not reduced significantly compared with having CHP capacity. In all cases the biomass consumption is reduced by the removal of the CHP capacity; however, this is related to a lower net export of electricity and the increase in offshore wind power capacity.

The effect of the net export of electricity can be investigated by changing the simulation strategy used in EnergyPLAN from Market Economic Simulation to Technical Simulation. This change means that the thermal plants' operation is changed from being aimed at reducing the costs of the energy system, e.g. by producing for export at high electricity market prices, to instead be operated to reduce fuel use and import of electricity while maintaining the electricity system stability of the modelled energy system. With this simulation strategy, the change in offshore wind power capacity is now 77 MW for CCGT with CHP capacity, 41 MW for the Woodpellet option, and 60 MW for SCGT. With this strategy, removing the CHP capacity reduces the change in the net export of electricity by around 0.2 TWh/year regardless of technology, as more electricity is used for the HPs in DH systems. Though the system still has a net export of electricity of more than 15 TWh in all cases. With this simulation strategy, removing the CHP capacity increases the biomass consumption for the Woodpellet and SCGT technologies with 0.46 TWh and 0.24 TWh, respectively. With the CCGT, the biomass consumption is reduced by 0.82 TWh, partly due to the higher offshore wind power capacity installed, which account for about 0.3 TWh of that decrease, but also due to the higher electric efficiency of the CCGT that limits the effect of removing the CHP capacity. The high efficiency of HP still allows for highly efficient use of biomass for heating in the way of first biomass gasification, then CCGT and then HP ($83\% \cdot 61.5\% \cdot 3.5 = 179\%$).

As such, the analyses indicate that the use of large-scale CHP units might not be significant in relation to keeping the biomass consumption at low levels, as long as the replacement power plant is highly efficient and sufficient other low-cost heat sources for DH, such as HPs, are available in the system. However, the overall differences are minor.

6.2.3.3 Heat pumps for district heating production

The scenarios all make increased used of electric-driven HPs to produce DH, as shown in Figure 56. As shown in the previous research, the electric-driven HPs are mainly used to integrate VRE sources, such as wind power, into the DH system, as well as to increase the utilisation of the VRE production in the energy system, due to a potential for flexible operation of the HPs for DH by the utilisation of large heat storages and a variation of heat-producing technologies. As such, it is most relevant to focus on the scenarios in 2050, but results from 2035 are also presented.

Table 11 shows the capacities of the DH-based HPs, the COP, and the share of the DH production at the medium fuel price level and external electricity market price level of 47 EUR/MWh.

Heat sector

Table 11 – Data for the HPs for DH in each scenario. The share of DH production is based on the medium fuel price level and the 47 EUR/MWh electricity market price level.

	Capacity [MW _e]	COP	Share of DH production
ST2035	495	3.5	23%
GCA2035	861	3.5	33%
IDA2035	700	3.0	28%
ST2050	730	3.5	35%
GCA2050	1,020	3.5	42%
IDA2050	700	3.5	26%

As shown in Table 11, in 2050, IDA2050 has the lowest share of DH from electric-driven HPs with 26% of the total DH production, due to a higher share of excess heat from industrial and electrofuel production as well as geothermal as shown in Figure 56, and GCA2050 has the highest share with 42%.

In this, it is investigated what the effects on the DH system are on the entire energy system when changing this capacity of DH-based HPs. This is done by varying the installed capacity in each scenario from 0% to 200% as shown in Table 11, in intervals of 25%. In the first analyses, no other changes are made to the DH production capacities, meaning that at lower HP capacities the other DH production technologies already present in each scenario are producing the missing heat from the HPs. As all scenarios have fuel boiler capacity able to cover the peak demand, all the DH demand is met regardless of the reduced HP capacity.

Figure 60 and Figure 61 show the DH production at the different levels of HPs tested for the scenarios GCA2050 and IDA2050, respectively. These scenarios are shown in more detail as they represent the highest and lowest HP share in 2050. The results shown in the two figures are with medium fuel price level and external electricity market price level of 47 EUR/MWh.

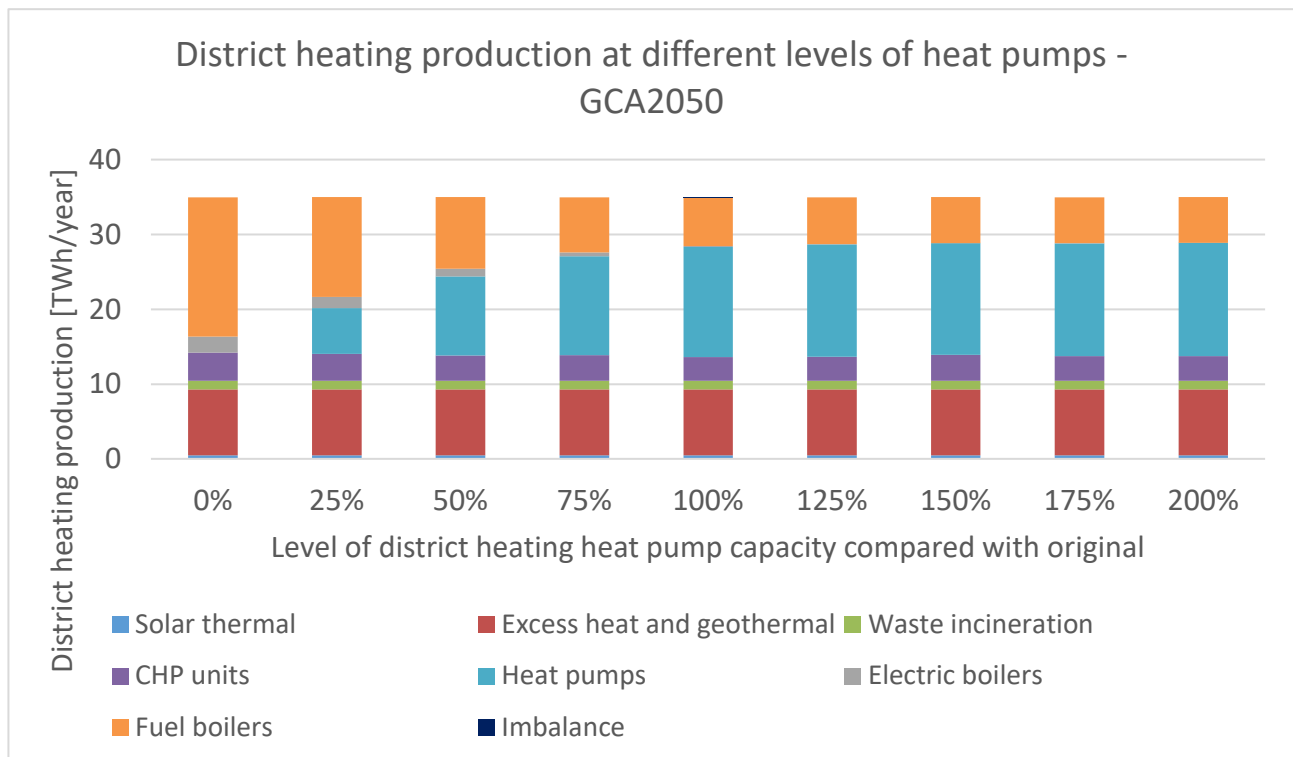


Figure 60 – DH production in the GCA2050 scenario at different levels of HP capacity with no replacement technologies

Heat sector

As shown in Figure 60, in the GCA2050 scenario as the HP capacity is reduced the missing DH production from the HPs is instead being produced mainly by the fuel boilers installed in the system, as their capacity is set to be able to meet the peak demand of the DH system, they have spare capacity that can be utilised. The electric boilers also are used more, however, to a much lesser extent. Increasing the capacity of the HPs, however, have little to no effect on the production of DH.

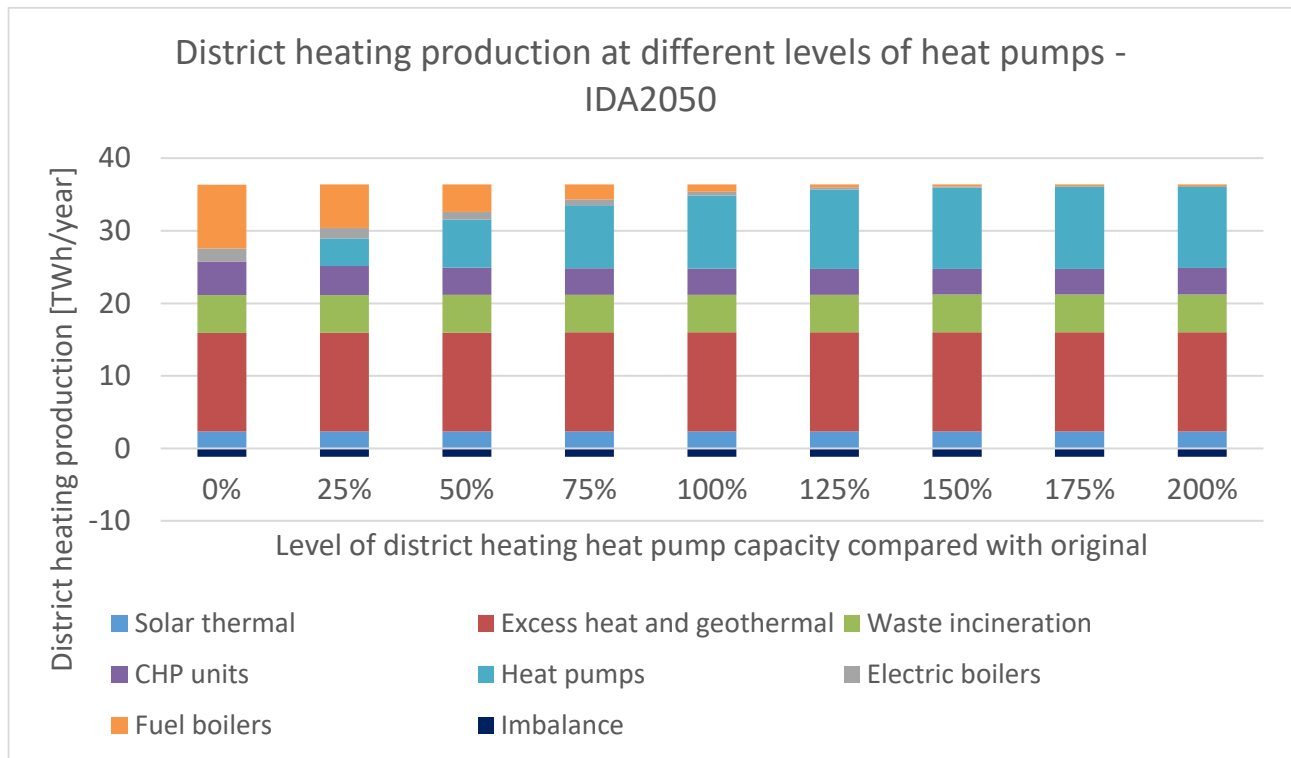


Figure 61 - DH production in the IDA2050 scenario at different levels of HP capacity with no replacement technologies

As shown in Figure 61, in the IDA2050 scenario as the HP capacity is reduced, the missing DH is instead being produced mainly by the fuel boilers installed in the system, similar to the GCA2050 scenario. However, in the IDA2050 scenario besides increased production on the electric boilers also the CHP units increase their production of DH. Increasing the capacity of the HPs decreases the production of DH on the fuel boilers, and minor amounts on the electric boilers and CHP units.

The approach is tested on all scenarios at the three fuel price levels and the 16 EUR/MWh, 47 EUR/MWh and 77 EUR/MWh electricity price levels. The ranges of the change to the total annual cost, is shown in Figure 62, where the range indicates the variation in total annual cost due to the price levels used.

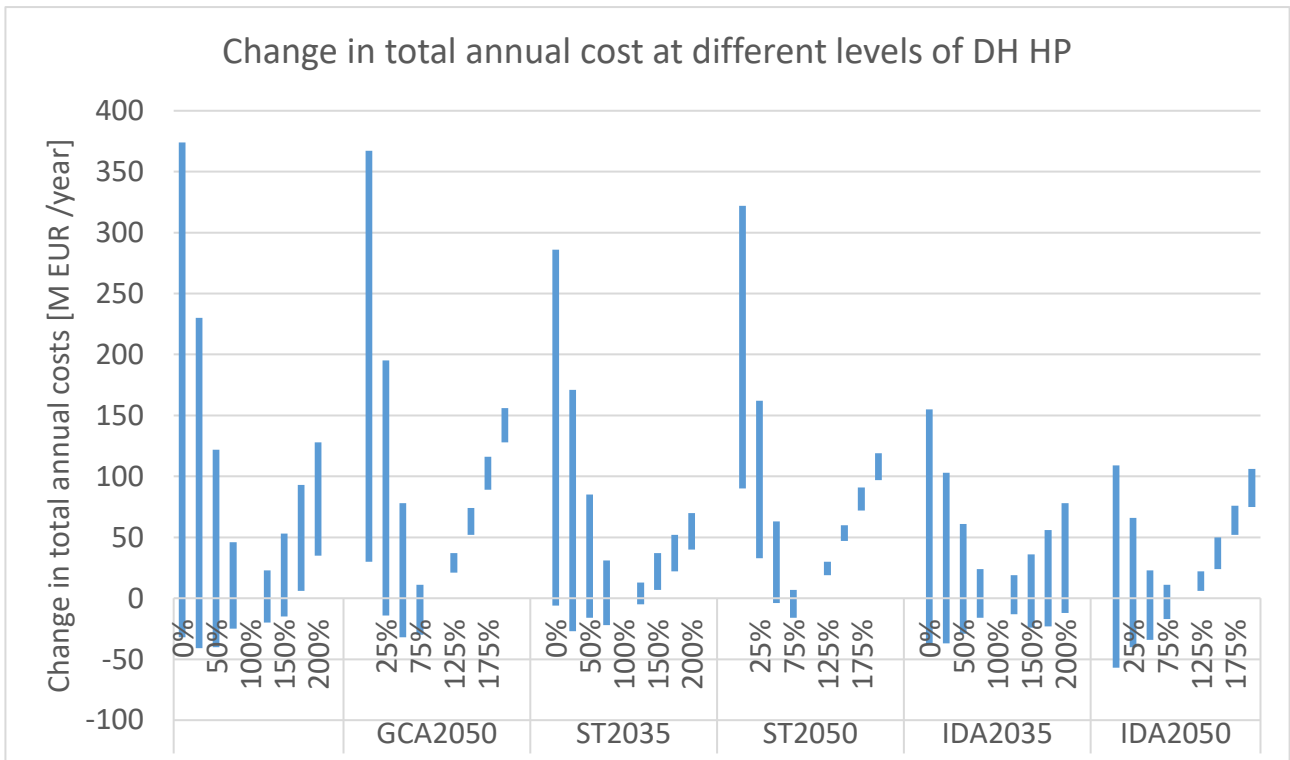


Figure 62 – Ranges for change in total annual costs at different levels of HPs in DH. Percentage compared with the initially installed capacity in the scenario. No replacement technology is installed in each scenario.

As shown in Figure 62 at lower levels of HP capacity, the results are sensitive to the used projections for fuels and electricity. This is especially true for the ST and GCA scenarios, as these mainly must use fuel boilers instead of the HPs. The IDA scenario is less sensitive to this, as it includes more CHP units. All scenarios seem to have a suitable level of HP capacity for DH installed at the outset, as more HP capacity generally increases the cost of the energy system. In IDA2035, this is unclear compared to other scenarios, which is due to the lower COP of the HPs in that scenario compared with the other scenarios.

Besides reducing the total annual costs of the system, HPs for DH systems have also shown to be useable to reduce the biomass consumption of a renewable-based energy system. Figure 63 shows the ranges in the change of biomass consumption for each scenario.

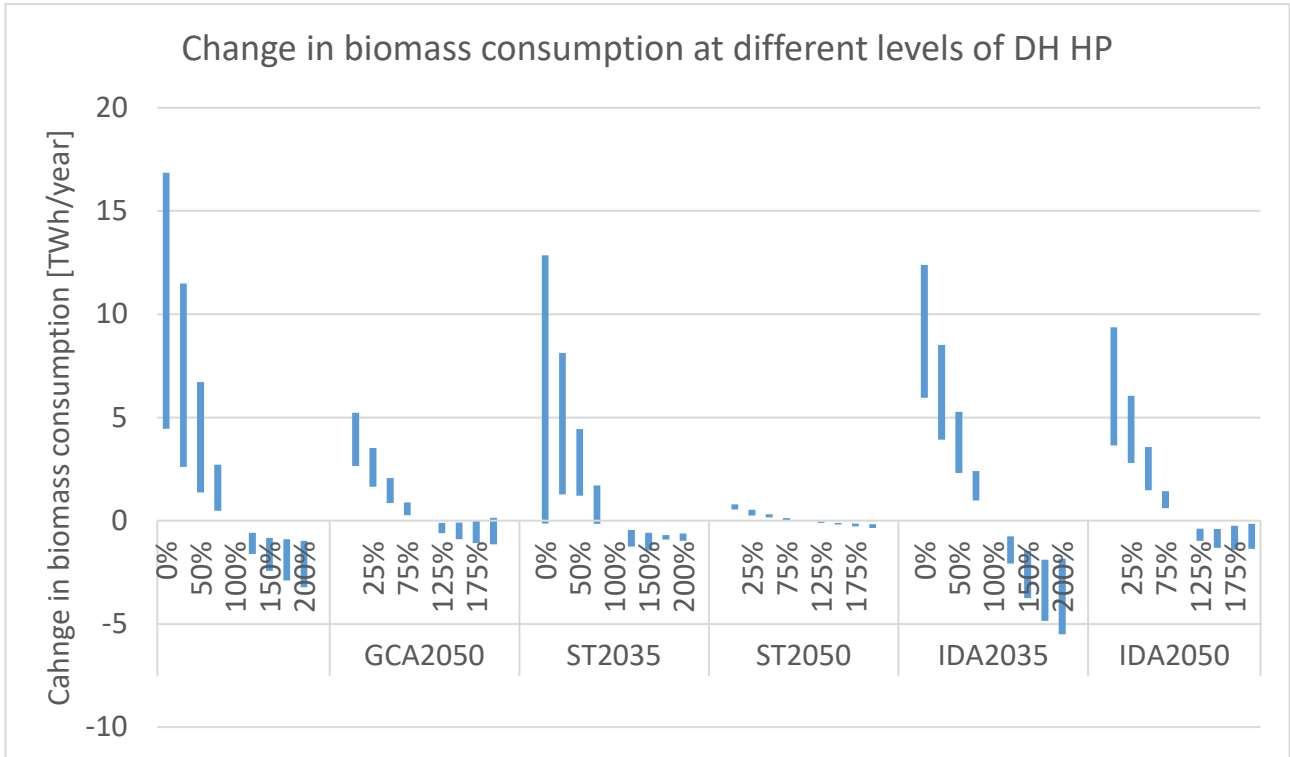


Figure 63 - Ranges for change in biomass consumption at different levels of HPs in DH. Percentage compared with the initially installed capacity in the scenario. No replacement technology is installed in each scenario.

As shown in Figure 63, lower HP capacity generally results in higher biomass consumption, and higher generally results in lower biomass consumption. There is some uncertainty to what the magnitude of the difference is, depending on the fuel and electricity price levels, as, e.g. a higher electricity market price makes CHP and fuel boilers more competitive. Primarily the 2035 scenarios show large variations in the change in biomass consumption at lower levels of HP capacity.

The results are shown in Figure 62 and Figure 63 assumes that no replacement technology is installed in the DH systems. Though, only removing HP capacity might be a fair comparison, as the DH companies would likely implement some other low short-term marginal cost heating solution. As such, the effect of adding geothermal as replacement is analysed. The geothermal replacement added is set to be equal to the yearly DH production from the removed HP capacity. However, where the HP operates flexible, the geothermal produces as a baseload throughout the year.

Figure 64 shows the ranges in changes of total annual costs similar to what was shown in Figure 62, however, here geothermal is added as a replacement for the removed HP capacity.

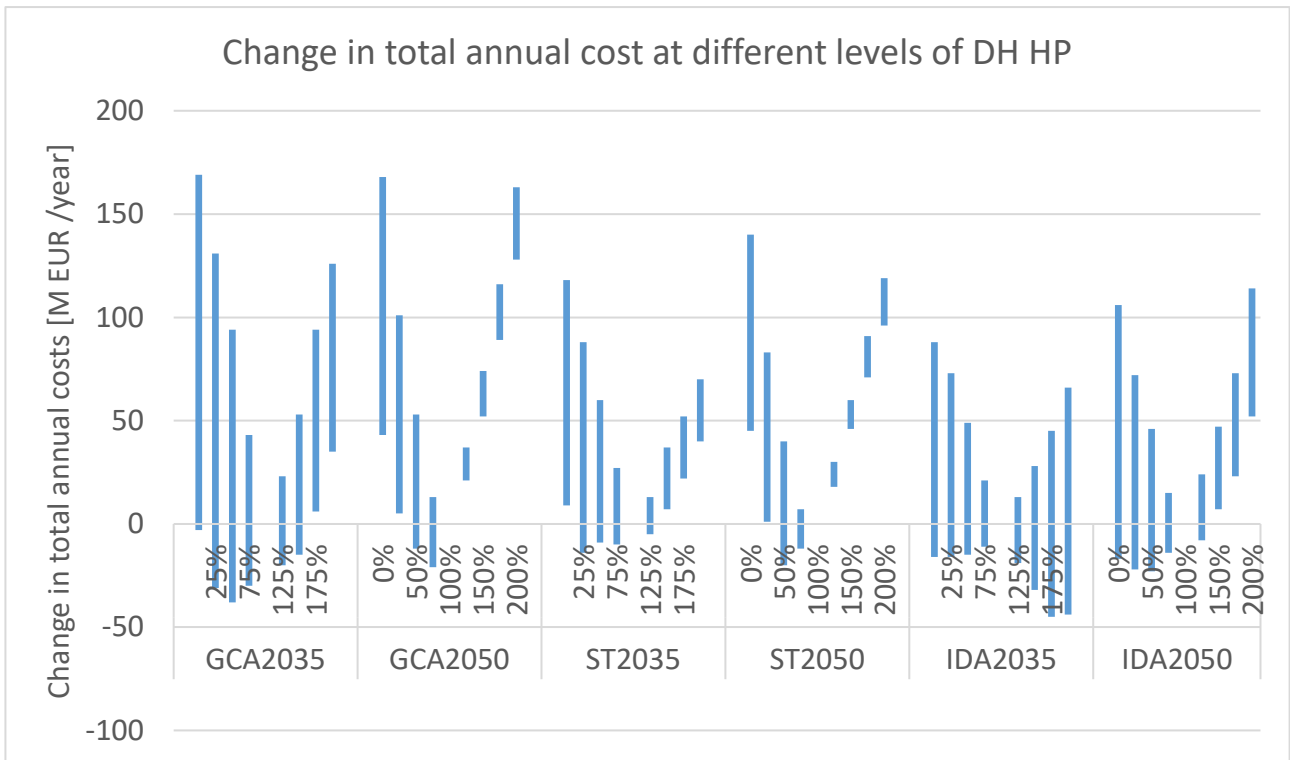


Figure 64 - Ranges for change in total annual costs at different levels of HPs in DH. Percentage compared with the initially installed capacity in the scenario. With geothermal energy replacing at reduced HP productions.

Figure 64 shows similar results as Figure 62, though the magnitude of difference in the ranges is reduced, especially for the GCA and ST scenarios.

Figure 65 shows the ranges in change of biomass consumption for each scenario, like Figure 63, however, here geothermal is added as a replacement for the removed HP capacity.

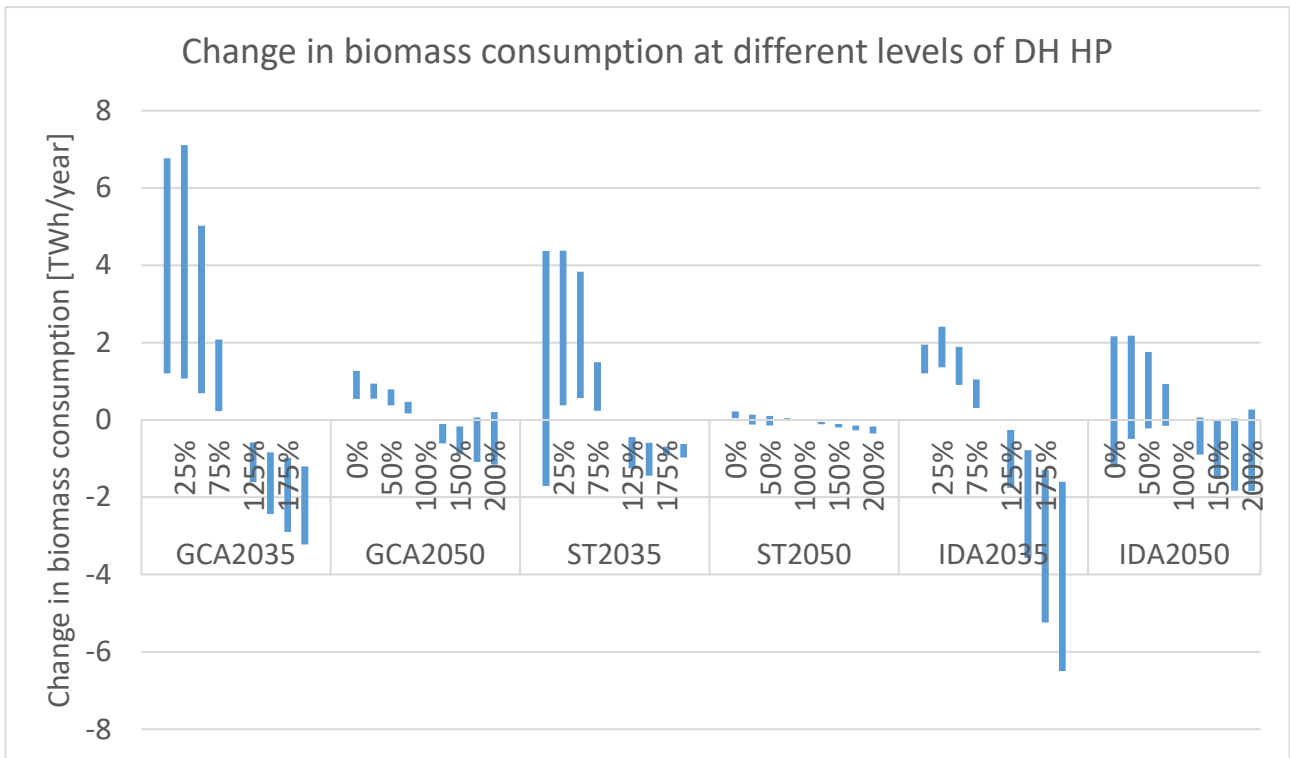


Figure 65 - Ranges for change in biomass consumption at different levels of HPs in DH. Percentage compared with the initially installed capacity in the scenario. With geothermal energy replacing at reduced HP productions.

Again, Figure 65 shows similar results as Figure 63, though the magnitude of difference in the ranges is reduced, especially for the GCA and ST scenarios.

Another technology that could be tested as a replacement technology for HPs is CHP units. The ST and GCA scenarios have a relatively low capacity of large-scale CHP and power plants installed in Denmark, instead relying on more transmission capacity to the surrounding countries. It is therefore relevant to investigate the effect of having large-scale CHP units for producing DH instead of the HPs in the ST and GCA scenarios. In this analysis, only HP capacity delivering to DH areas categorised as central is included, as it is assumed that these would be large enough to utilise heat from a large-scale CHP plant. The replacement capacity of CHP is set to equal the heat capacity of the removed HP capacity, and it is assumed that the replacement CHP have the same efficiencies as the existing large-scale CHP capacity. Only ST2050 and GCA2050 are analysed in this.

Figure 66 shows the change in total annual costs at the different electrical capacities of CHP units at the three different fuel price levels and three electricity market price levels (16, 47, and 77 EUR/MWh).

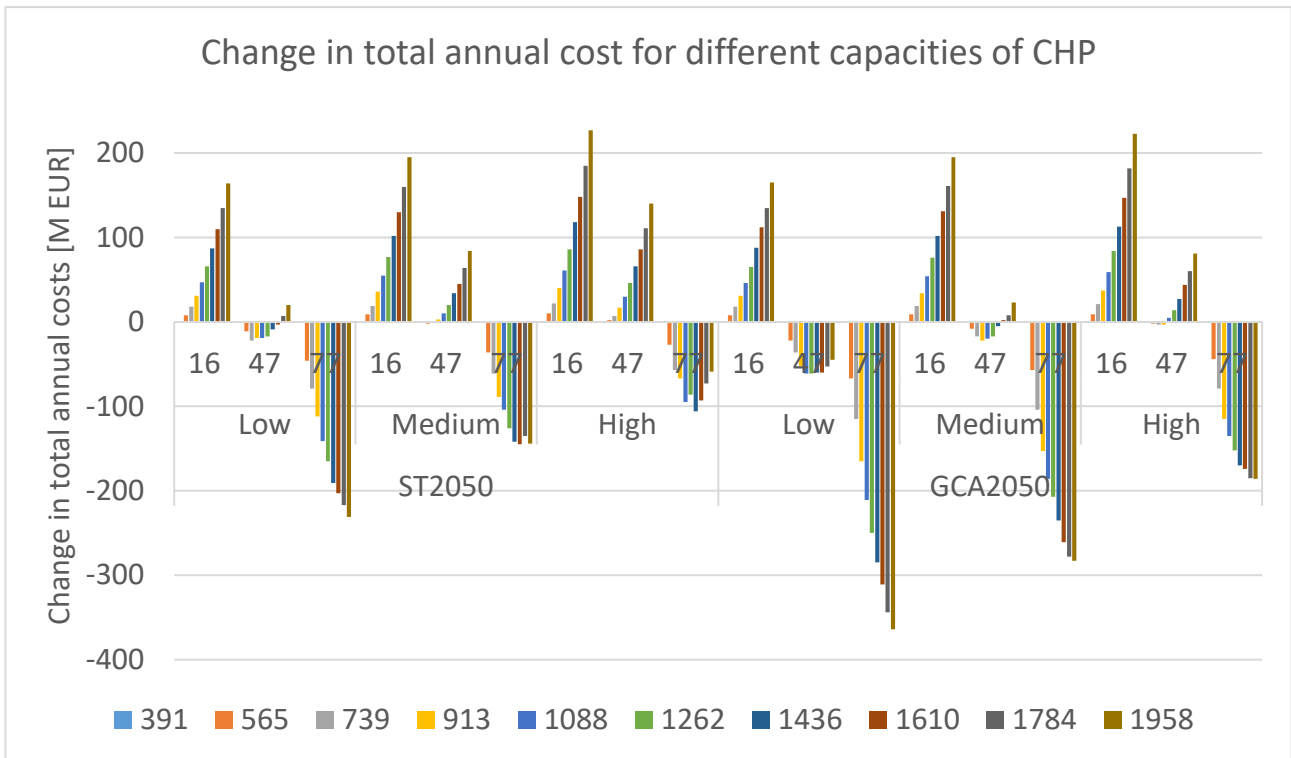


Figure 66 – Change in total annual cost at different levels of large-scale CHP electric capacity at different fuel and electricity market price levels.

As shown in Figure 66, the value of CHP capacity instead of HP capacity is dependent on the price projection used. High electricity price and low fuel prices favour CHP and vice versa.

However, from a system perspective, it could also be argued that since the ST2050 and GCA2050 scenarios only have a relatively low amount of large-scale CHP and power plants and instead utilises relatively high capacities of transmission to surrounding countries to ensure the stability of the electricity system, then when adding more CHP capacity to the system, then the transmission line capacity could also be reduced, as the need for it to ensure stability is reduced. Here it is simply assumed that the transmission line capacity can be reduced 1:1 when installing electric CHP capacity in Denmark. Figure 67 shows the same analyses as in Figure 66, except here reductions in transmission line capacity are included with the increasing amount of CHP capacity.

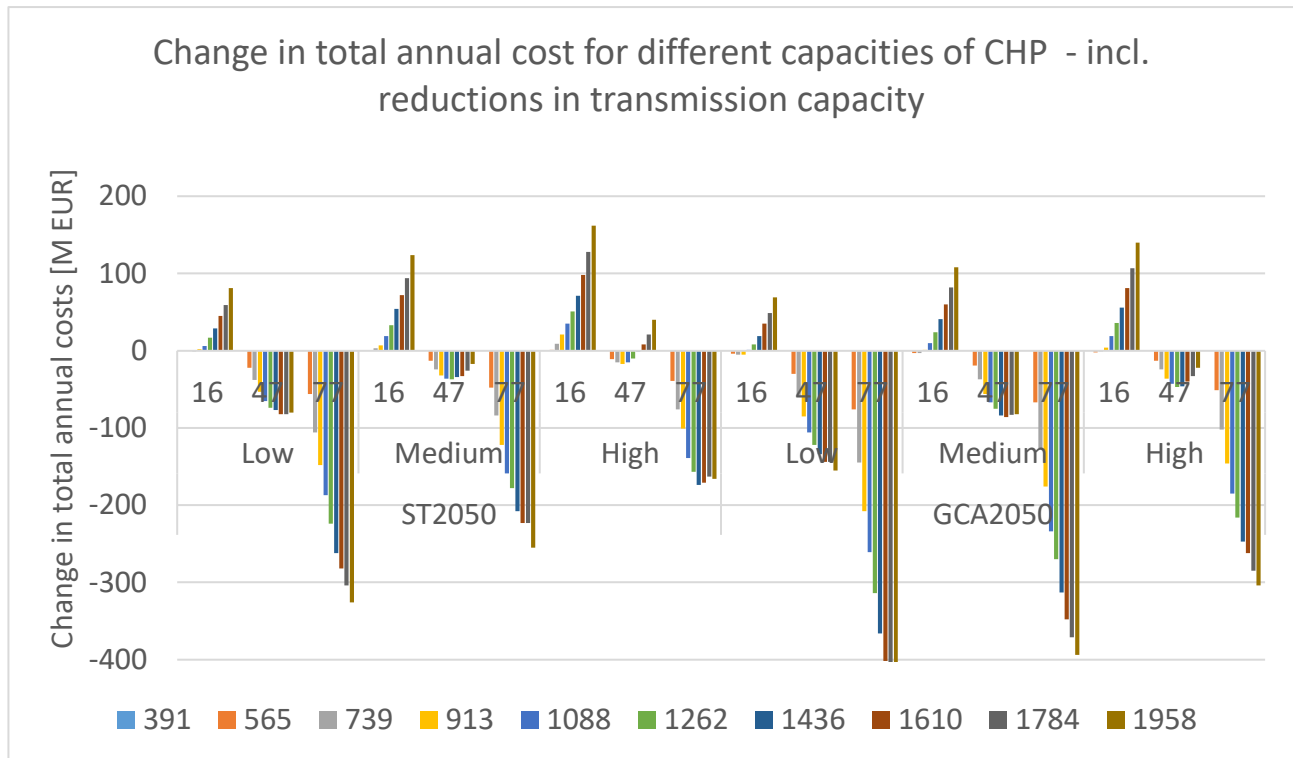


Figure 67 – Change in total annual cost at different levels of large-scale CHP electric capacity at different fuel and electricity market price levels. Reduction in transmission line costs included.

As shown in Figure 67, when including the cost savings from transmission lines then increasing the CHP capacity as a replacement for HPs reduces the total annual costs of the energy system in the two scenarios at all market price levels, except at the low electricity price level of 16 EUR/MWh. Compared with not adjusting the transmission line capacity, the yearly import and export of electricity are virtually unchanged in all price scenarios. Though it should be noted here that the simulations in EnergyPLAN do not account for breakdowns of units or transmission lines, nor does it include transmission of electricity through the Danish energy system to be used in other countries. However, the analysis seems to indicate that large-scale CHP units could play a role in keeping the total annual costs of the Danish energy system low.

6.2.3.4 District heating storages

The previous research has shown that the ability of DH to integrate VRE into the energy system is primarily due to the ability to have cheap and efficient large-scale heat storage options available. Heat storages for DH can be categorised into two overall groupings depending on the purpose of the storage; short-term storages for up to a few weeks of storage, and seasonal storages meant to store heat energy between seasons. Generally, seasonal storages are used for increased utilisation of, e.g. solar thermal or industrial excess heat, whereas the short-term storages typically are used for the flexible daily operation of the DH system. As such, for investigating the ability of the DH systems to integrate VRE into the energy system, it is most relevant to investigate the short-term storage capacity. All the scenarios include short-term storage for DH, which is 30 GWh in the ST and GCA scenarios, and 112 GWh in the IDA scenarios. To investigate the effect of the DH short-term capacity, the three fuel market price levels and the 16, 47, and 77 EUR/MWh electricity market price levels are used. The storage capacities are varied between 0 to 180 GWh in intervals of 30 GWh. It should be noted, however, that the EnergyPLAN simulations do not consider local conditions in the different

DH systems that could provide increased value to the short-term storage, such as grid or operational limitations. As such, this analysis is expected to undervalue the benefits that short-term DH storages would provide the energy system.

Figure 68 shows the ranges for the change in the total annual cost of the different levels of short-term heat storage in DH systems, compared with the original installed storage capacity of each scenario.

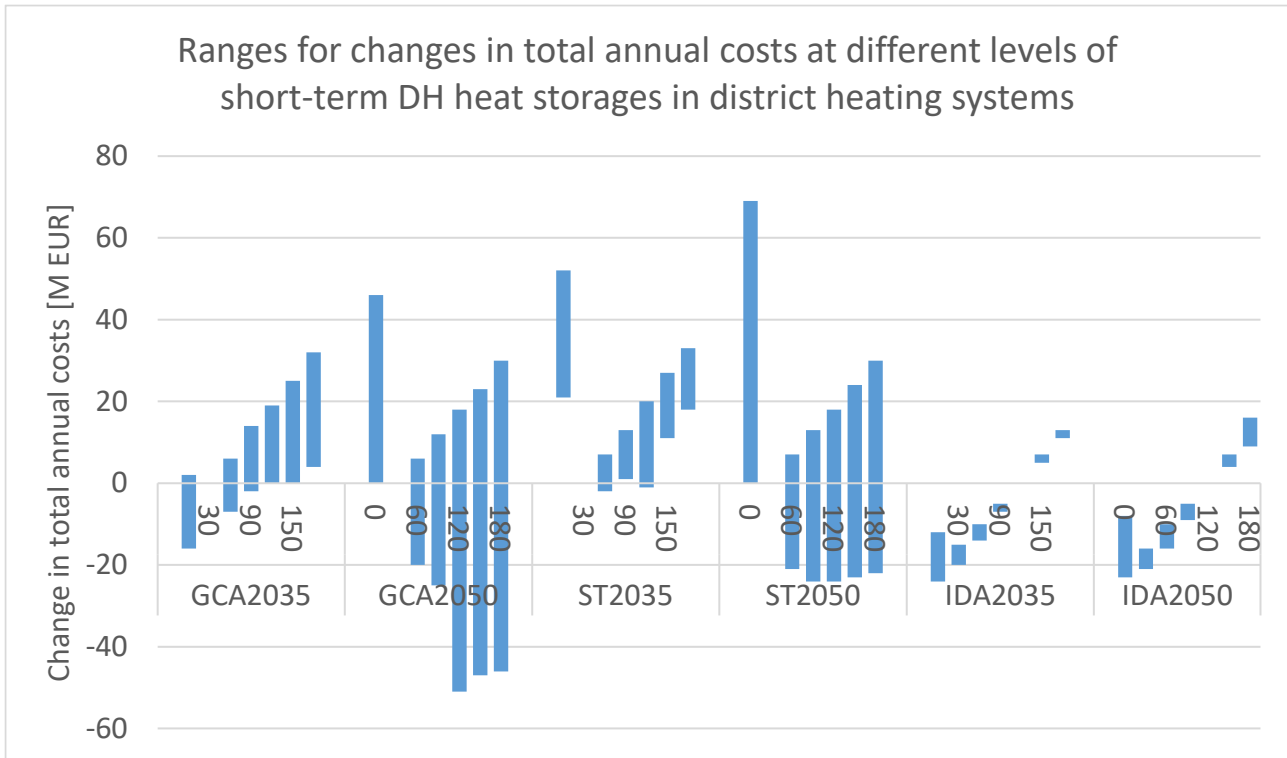


Figure 68 - Ranges for change in total annual costs at different levels of short-term DH heat storages in DH systems, when compared with the original scenarios heat storage capacity, which is 30 GWh in the ST and GCA scenarios and 112 GWh in the IDA scenarios.

As shown in Figure 68, in the GCA2050, ST2035, and ST2050 scenarios, completely removing the short-term DH storage increases the total annual costs regardless of price projections used. Removing the short-term DH storages in the GCA2035 scenario reduces the total annual cost in all cases, except for the price projection with the high electricity and fuel price levels. In the IDA scenarios removing the short-term DH storages reduce the total annual costs in all price projections. Generally, the DH storages effect on the total annual costs is very depending on the price projections used, where the benefit of the short-term storages is most considerable for the high electricity market price level, as the absolute differences in hourly electricity market prices are most considerable at that price level. This is especially true in the ST and GCA scenarios, as these are more affected by changes in the electricity market prices, due to being more reliant on import and export of electricity. The effect of different price projections is not as significant in the IDA scenario, as it has more different production technologies for DH and efficient thermal plants for electricity production. It is clear across the scenarios that some short-term DH storages are generally a good idea from a total annual cost perspective, especially as it is expected that the total value that short-term storages give to the energy system is undervalued in the national energy system simulations made here.

Another import aspect with regards to DH storages is their ability to reduce fuel consumption by allowing more efficient time of use of energy. Figure 86 shows the change in biomass consumption similarly to how the change in total annual costs is shown in Figure 68.

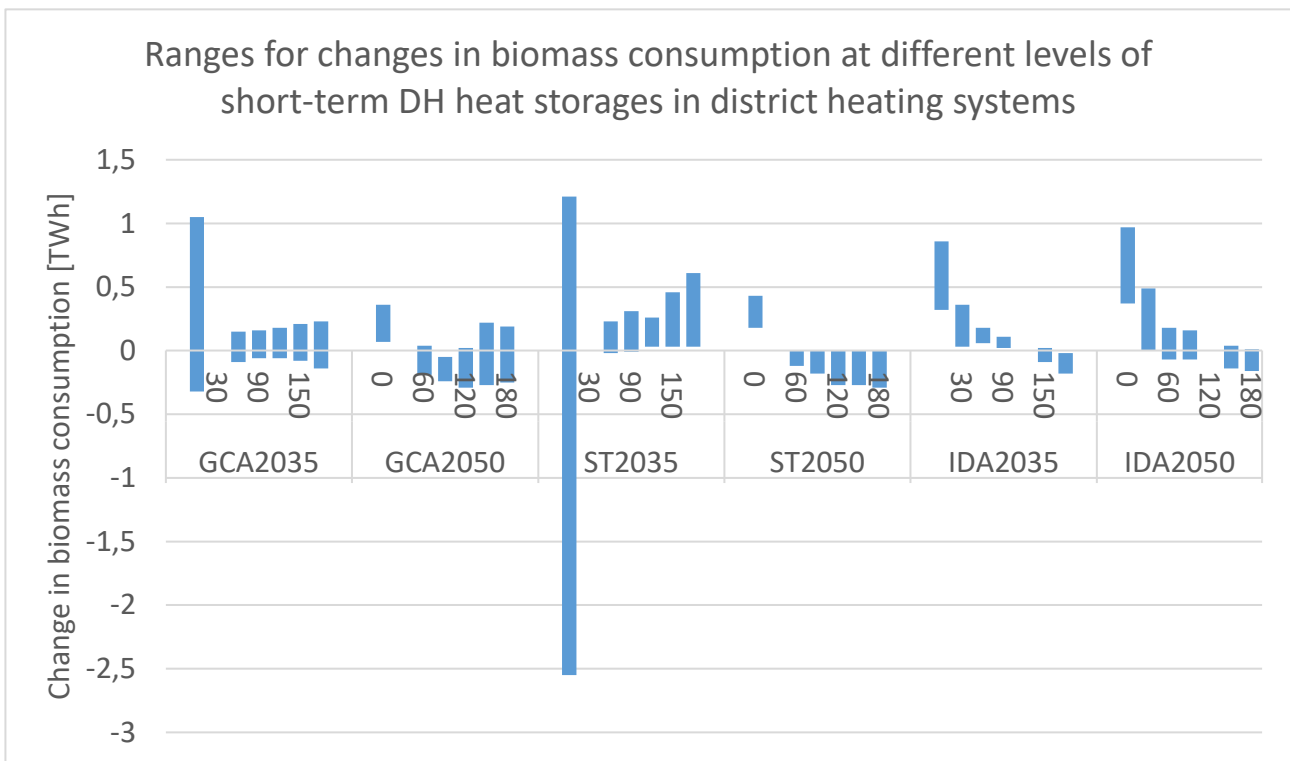


Figure 69 - Ranges for change in biomass consumption at different levels of short-term DH heat storages in DH systems, when compared with the original scenarios heat storage capacity, which is 30 GWh in the ST and GCA scenarios and 112 GWh in the IDA scenarios.

As shown in Figure 86, in the IDA scenarios, the use of biomass decreases with larger capacities of short-term DH storages. The ST and GCA scenarios show increasing or stable biomass consumptions at larger capacities, where the ST2050 scenario also shows a small decrease at larger capacities with some price projections. Removing the short-term storages in the GCA2035 and ST2035 scenarios have a large impact on the biomass consumption, which is due to a larger share of the CHP plants being based on biomass-fired units with lower electric efficiency than in the IDA scenario, meaning a small change in the use of CHP has a larger effect on the biomass consumption. The biomass consumption is less affected in the ST2050 and GCA2050 scenarios as the electricity system here is based on import and export of electricity, and thereby less CHP capacity that could utilize the short-term storages to increase revenues from electricity market trading.

6.3 Conclusions on the heat sector

This section summarizes the main takeaways for the analyses conducted on the heat sector, including all space heating demands, hot water consumption demands, and losses in the DH systems.

In all scenarios, the heat sector remains a vital energy sector, as even with heat savings, the heat demand still accounts for a large share of the end-user demand. Though heat savings at the end-users are assumed to be part of all the scenarios, it is only detailed in the IDA scenario where approximately 40.2% heat savings

are implemented. As the details of heat savings are known for the IDA scenario, as opposed to the heat savings in ST and GCA, the energy system effects of end-user heat savings are only analysed in the IDA scenario. In the IDA scenario, the lowest total annual costs of the energy system are found for heat savings of approximately 32% compared with 2010. However, heat savings also result in reduced biomass consumption, which continues to decrease linearly with increasing heat savings. As the biomass amount is likely limited in a sustainable future energy system, heat savings until around 42% could provide reductions in biomass consumption at a relatively low cost for the energy system. Going from 32% to 42% heat savings increases the total annual cost of the system by about 34 M EUR (less than 0.2 % of total annual costs of the IDA2050 scenario) but reduces the biomass consumption by about 2.2 TWh/year (around 3.5% of the total biomass consumption of the IDA2050 scenario).

The production and storage in DH systems and individual heating solutions are also expected to change. In the three scenarios, individual heating units are changed from mainly fuel boilers to instead be mainly electric-driven HPs. This change is analysed in this chapter, and it is found that if biomass boilers are used instead of electric-driven HPs for individual heating, both the biomass consumption and the total annual cost of the energy system will increase. This conclusion stands regardless of the analysed energy system scenario or the market prices for fuel and electricity, though the magnitude of increase in total annual costs is affected by the cost of biomass in all scenarios. In the ST and GCA scenarios, the international electricity market prices also significantly affect the energy system costs. Using more solar thermal in connection with the individual biomass boilers reduces the increase in total annual costs, though only up to a certain level of solar thermal. In all scenarios, heat storages are used in connection with individual electric-driven HPs and solar thermal, and it was found that these storages can reduce the biomass consumption of the energy system, as they can allow the HPs to operate more flexible within a few days. As this flexibility is limited in temporal scale, the effect is only up to a certain point and depends on the amount of other flexible electricity demands in the scenario.

Another part of the analysis focuses on the energy system effects of utilizing different large-scale thermal CHP and power plants. The technologies tested are combined cycle gas turbine (CCGT), simple cycle gas turbine (SCGT) and large wood pellets extraction plant. These are mainly tested in the IDA2050 scenario as this has the largest thermal plant capacity, and thereby the effects of changing technologies should be more evident. In the tests, the electric capacity for CHP and power plant capacity is kept constant. It is found that the high electric efficiency of the CCGT provides the system with the lowest costs and lowest biomass consumption. The CHP capacity's effect on the biomass consumption has also been tested, by removing the CHP capacity but keeping the condensing capacity of the three technologies. Though the overall differences are minor, it is found that the use of large-scale CHP units might not be necessary in relation to keeping the biomass consumption at low levels, as long as the replacement power plants are highly efficient and sufficient other low-cost heat sources for DH, such as HPs, have left overcapacity that can allow them to replace a large share of the DH that would otherwise have been produced by CHP.

Electric-driven HPs are extensively used for DH production in all the scenarios, though mostly in the ST2050 and GCA2050 scenarios. The energy system effects of these units are analysed by increasing and decreasing their capacity. This is first tested without changing the capacities of the other DH technologies, and here it is found that for the total annual costs the optimal sizing is very dependent on the price projection used, though the existing installed capacity of HPs seem suitable in all scenarios when no other changes are made to the

DH systems. Increasing the HP capacity decreases the biomass consumption, though the effect of this is greatest at low levels of HP capacity. Similar conclusions are found if geothermal is used as a replacement technology for DH production, though the variations due to used price projection are reduced by having this technology. The ST2050 and GCA2050 scenarios have the lowest capacities of large-scale CHP capacity, so in these scenarios, the energy system effects of using CHP capacity as a replacement for the HPs is investigated. Here it is found that CHP, as replacement technology for HPs, only reduces the total annual costs of the energy system at high electricity market price levels. Though, if increased CHP capacity also allows for reduced transmission line capacity, then the CHP replacement would also reduce the total annual costs at the medium electricity price levels.

Short-term storages for DH are also analysed, and it is found that in most cases, completely removing short-term storages increases both the total annual costs and biomass consumption of the energy system. In scenarios with many different DH production technologies and high levels of excess and geothermal heat, the value that the short-term storages provide in terms of flexibility is low, and in these scenarios the positive effects of short-term storages are low. Removing the short-term storages can in these result in a reduced total annual cost, depending on the price projection used. However, it should be noted that the analyses presented in this study are expected to undervalue the benefits of short-term storages on local and daily operation at individual DH systems. The reason for this is that in EnergyPLAN individual DH systems are aggregated into two overall categories, allowing for a more overall efficient use of the storage capacity and does not account e.g. limitations in DH grids.

7 Renewable fuels in the Danish energy system

Renewable fuels for power generation, industry and transport have been previously studied as part of energy system analyses. The term renewable fuel is generic and refers to fuels produced solely from renewable carbon and electricity sources. The terminology for these types of fuels is clarified by Ridjan et al. [68] suggesting that the term *renewable electrofuel* should only be used when electricity and carbon are sourced from renewable energy sources. In contrast, the term *renewable synthetic fuel* should be allocated to fuels produced mainly from biomass resources. This report refers to renewable sources only, but it differentiates between electrofuels and synthetic fuels.

7.1 Previous research

In 2014, Ridjan et al. [69] have analysed the potential of renewable fuels in future energy systems, finding out that electrofuels produced from wind power have the benefit of lowering the biomass demand while simultaneously increasing the energy system flexibility. In another study, Connolly et al. [70] find that electro-methanol or electroDME have a higher potential to replace refined oil products compared to renewable methane and that by 2050, some of these fuels even have the potential to have a lower cost than the equivalent fossil fuels. The authors of this study also highlight the importance of biomass gasification to deal with the biomass bottleneck in the short term, detailed with examples on the state-of-the-art in Denmark and Sweden [71]. In another study, Lester et al. [72] find that electrofuels, particularly the ones using biomass can play a more prominent role in the transport sector by 2050, as they are more economically attractive than CO₂ electrofuels. In contrast, Albrecht & Nguyen [73] analyse the prospects of utilising CO₂ electrofuels in Denmark relying solely on the wind and solar resources of the country, finding that the theoretical wind potential of Denmark is sufficient to supply the countries transport demands but acknowledge their significantly higher costs than equivalent fossil fuels.

The research on renewable fuels is put on a broader context in the CEESA Report [74], where different fuel pathways for the transport sector were created and compared. The study highlights the unique issues that need to be solved for the transport sector, such as the considerable growth in demand, the need for energy-dense fuels, and the concerns about the availability of sustainable resources. The results show that the amount of electrofuel that can be incorporated into the energy system in the future will be very dependent on the technological development of some critical technologies, such as biomass gasification, carbon capture and recycling and electrolyzers, as well as on the amount of sustainable biomass that can be harnessed in the energy system. As part of the same project, Mathiesen et al. [75] describe the more significant role of biomass gasification and gas storages in conjunction with electric vehicles and electrofuel production as well as DH systems. In another study, the same authors [76] find that electrolyzers (in this case SOEC), can also participate as energy system balancing reserves, but it will most likely not be required as several other flexible technologies could be used instead due to their better performance and lower costs. The authors also find that investments in electrolysis should be driven by the need for meeting the transport fuel demand, as their most significant contribution is for fuel production rather than for renewable energy integration. The grid stability should be seen as an additional benefit from electrolyser integration.

In her thesis, Ridjan [77] calls for the necessity to rethink the production cycles of gaseous or liquid hydrocarbons for some modes of transport while at the same time creating flexibility that will enable an extensive

penetration of fluctuating sources into the electric grid. She finds electrofuels for heavy-duty transportation are technically and economically viable in energy systems and could play an essential role in future energy systems. The critical concern in the short term should be the development of critical technologies that are in common for the electrofuel production cycle, such as electrolyzers, biomass gasification and carbon capture and recycling. At the same time, the final fuels can be adjusted when the factors on the demand side of the transport sector are more precise.

Apart from biomass gasification, another possibility to synthesise renewable fuels is from wet biomass resources, like manure, organic or industrial waste. In [78], the authors make an overview of the existing biogas resources and biogas production in Denmark, including the mapping of manure, straw and municipal waste across municipalities in the country to determine the geographical locations for biogas upgrading and CO₂ methanation [79] across Denmark, also indicating that the biogas upgrade path is the cheapest one of the two, at the present cost level. CO₂ methanation is a costlier path, and even with the broader potential, such plants can be expected to diminish in the future as more RES is introduced, lowering the need for thermal energy producers, while biogas production could see an increase.

Not the least, and although already used extensively in this report, the IDA Energy Vision 2050 [1] should also be mentioned among the previous research. The analyses made in this study contributed to an energy strategy for Denmark. It is based on state-of-the-art knowledge about how low-cost energy systems can be designed while also focusing on long-term resource efficiency to demonstrate that technical possibilities are available to inspire short-term decision-making.

Based on the findings in the existing literature, this chapter is split into three main subchapters. First one deals with the role of biogas in the Danish energy system, the second deals with the role of biomass gasification, while the third part refers to the potential of achieving more flexibility in the energy system with the help of electrofuel production.

7.2 Analyses

7.2.1 Role of biogas in the Danish energy system

The energy transition in the Danish energy system must include the topic of renewable fuels for transport, industry and power plants. There is a variety of fuels and fuel production pathways that may offer a solution to this issue, but not all of them have the same socio-economic benefits. Biogas has often been put forward as a solution to replace natural gas and even to supply the Danish transport demand [80]. The issue of using biogas for electricity production (and biogas in general) is the limited availability for a fuel that is dependent on agricultural practices and food choices. The majority of biogas feedstock in Denmark is composed of manure and organic waste, which may not be feedstocks readily available in the future, being dependent on agricultural practices and dietary choices. However, the collection and conversion of biogas feedstocks to fuels is necessary to reduce the emissions from agriculture, but the production of biogas is primarily a waste treatment solution that can complement the other resources in the energy system.

The biogas production in Denmark was approximately 14 PJ in 2018, but depending on the feedstocks considered and the conversion method, this may vary in the future between 23-107 PJ [15], [80]. Naturally, it becomes relevant to understand what are the effects of using biogas and biogas-derived fuels for replacing

natural gas but also other potential renewable fuels in the energy system. For this purpose, biogas, bio-methane and electromethane (derived from biogas) replace natural gas and other renewable fuels in both the IDA and Energinet scenarios.

7.2.1.1 Results

We take as a starting point the IDA and ST2035 models, where natural gas is gradually replaced in six consecutive steps until no natural gas is left in the energy system. For this purpose, we use biogas, bio-methane and electromethane, as illustrated in Figure 70, and we allocate four cost levels for biogas feedstocks. The first level refers to these feedstocks as paid by the agricultural sector, meaning that their cost is 0. The next three levels refer to 4.5, 5.2 and 5.9 EUR/GJ, include a cost of feedstock and transport of the fuel to the biogas plants.

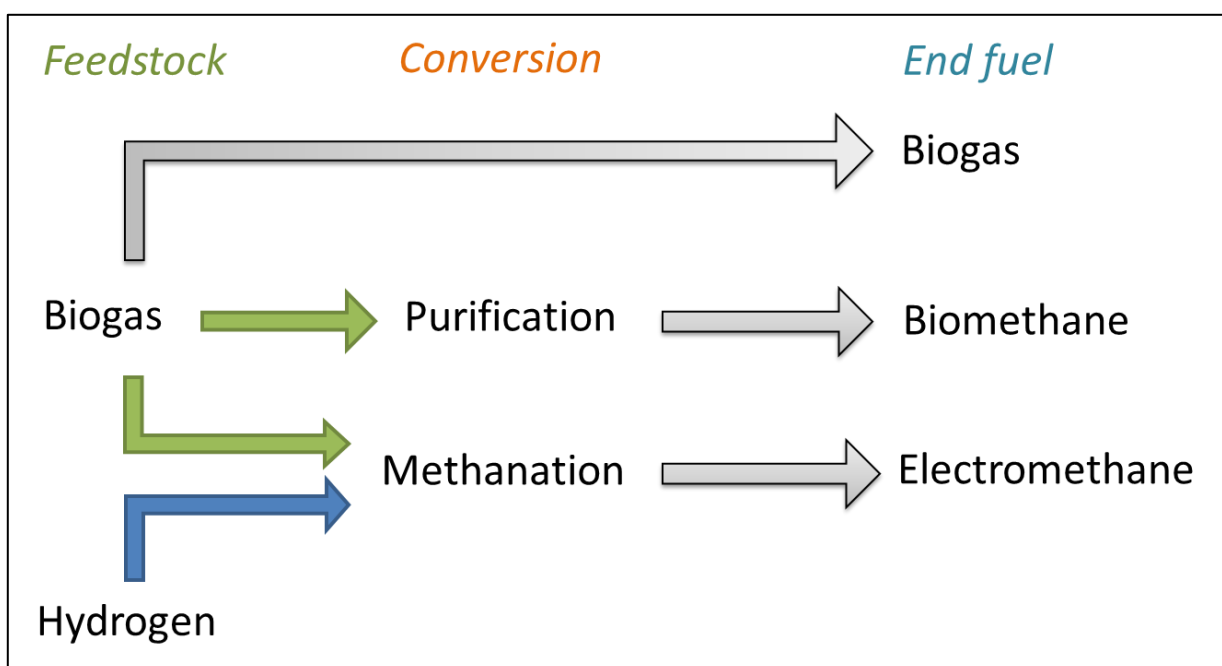


Figure 70 -Biogas and its derived fuels

The cost level used for natural gas is 10.4 EUR/GJ, and at this price level, the replacement of this fuel with biogas has the effect of increasing the total energy system costs as well as the total biomass consumption, illustrated in Figure 71. Even with the feedstocks paid by the agricultural sector, biogas is a more expensive fuel due to the high conversion cost, represented by biogas plants. At the same time, adding more biogas to the energy system can only have the effect of increasing biomass consumption.

Renewable fuels in the Danish energy system

	Biogas production	Feedstock price				Biomass consumption
		0	4.5	5.2	5.9	
1	7.5	0	121	140	159	44.5
2	11.8	18	209	238	268	48.8
3	16.0	36	296	336	376	53.0
4	20.3	55	383	434	485	57.3
5	24.5	73	470	532	594	61.5
6	28.8	91	557	630	702	65.8

Figure 71 - Energy system cost differences for using raw biogas in IDA2035 scenario. The left and right of the picture show the biogas production and total biomass consumption.

Even with a higher cost for natural gas, the addition of this fuel to the energy system can only increase the costs. In terms of CO₂ emissions, the benefits may be more substantial, as the addition of biogas may decrease them from 12.2 Mt in the reference scenario to 7.9 Mt in the scenario with the most massive biogas production. However, the availability of enough biogas resources may not allow for using such large quantities. Sustainable resources may not reach more than 20 TWh/year, which is already significantly more than the quantities used today, in which case the CO₂ reduction would be 2.5 Mt, to approximately 9.5 Mt. The cost of biogas feedstock may be a natural influencer for the adoption of this fuel.

The addition of raw biogas as replacement of natural gas may also pose other challenges too, such as the proximity requirement between biogas production and biogas end-use, or the necessity for a transport grid. An alternative for this solution is to purify the biogas to grid quality, but this solution is more expensive from the fuel production perspective. The cost of such a scenario is as expected higher (illustrated in Figure 72), but it may be a solution to reduce the emissions while also making use of the existing gas grid.

	Biomethane production	Feedstock price				Biomass consumption
		0	4.5	5.2	5.9	
1	7.5	0	122	141	160	44.5
2	11.8	33	223	253	283	48.8
3	16.0	66	325	365	405	53.0
4	20.3	66	426	477	528	57.3
5	24.5	98	528	589	651	61.5
6	28.8	131	629	702	774	65.8

Figure 72 - Energy system cost differences for using biomethane from biogas in IDA2035 scenario. The left and right of the picture show the biogas production and total biomass consumption.

The use of electromethane is different from the previous 2 cases, due to the new electricity demands for hydrogen production. The total biomass consumption is lower since the hydrogen in electrolysis can make use of the CO₂ in biogas. However, this comes at a higher cost than using biogas or biomethane, significantly higher even with the free biogas resources. The CO₂ emission reductions can account to 3.9 Mt CO₂ saved in the case with the highest biogas production, but if the same biogas resource used as in the case of biogas and biomethane scenarios, then the CO₂ reductions are slightly better than in the case of using biogas and biomethane.

Renewable fuels in the Danish energy system

	Electromethane production	Feedstock price				Biomass consumption
		0	4.5	5.2	5.9	
1	7.5	0	122	141	160	44.5
2	10.8	118	293	320	347	48.0
3	14.0	240	467	503	538	51.6
4	17.3	455	643	686	730	55.0
5	20.6	489	822	874	926	58.5
6	23.9	617	1004	1064	1124	62.0

Figure 73 - Energy system cost differences for using biomethane from biogas in IDA2035 scenario. The left and right of the picture show the biogas production and total biomass consumption.

To diversify the testbed, a similar approach was used, where biogas, biomethane and electromethane replace natural gas in the ST2035 models. Since Energinet scenarios are simulated in market analysis, three fuel price levels are used.

The results show that using biogas in a system with low fuel prices slightly increases the total energy system costs, while in a system with medium fuel costs, the addition of biogas with no price for feedstock slightly hardly influences the energy system costs. In a system, with high fuel prices, the addition of biogas reduces the cost of the energy system, unless a price is put on the biogas feedstock, in which case the costs increase, but the increase is marginal. A similar case occurs when using biomethane, while the use of electromethane entails significantly larger energy system costs across all fuel cost levels.

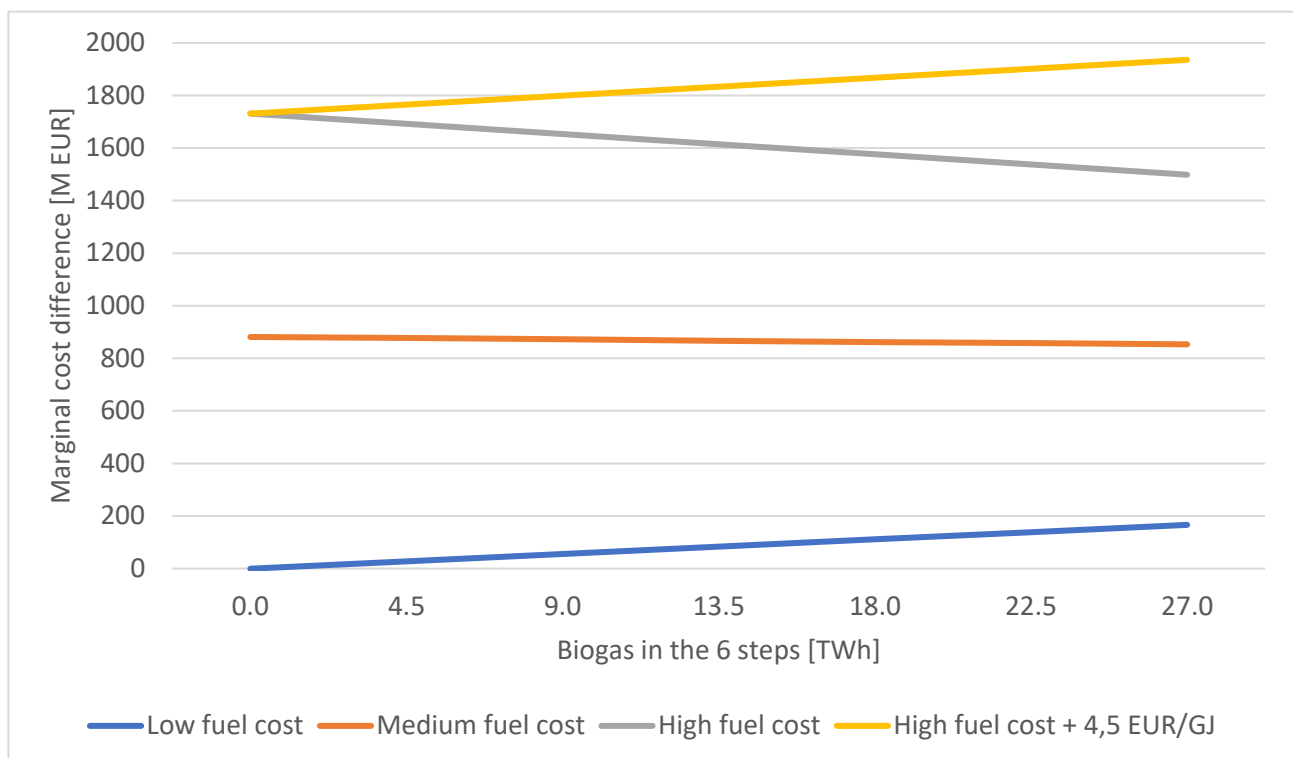


Figure 74 - Biogas with free feedstock cost replacing NGas in the Energinet ST2035 in the low, medium and high fuel price scenarios plus a scenario with a cost of 4.5 EUR/GJ for biogas feedstock.

Renewable fuels in the Danish energy system

The next analysis refers to using the same biogas and biogas-derived fuels, but this time as part of a 100% renewable energy system. In Korberg et al. [81] the energy system costs and biomass consumption are analysed for the case of Denmark in 2050. Here, a different approach is used, where a fixed amount of biogas, biomethane and electromethane (8.41 TWh) replace fuels from biomass gasification and biomass hydrogenation in power production and the industry as illustrated in Figure 75. The results are compared to an energy system based on the IDA 2050 scenario that does not use any biogas or biogas-derived fuels. The reference scenario in this part analysis is described in detail in [81].

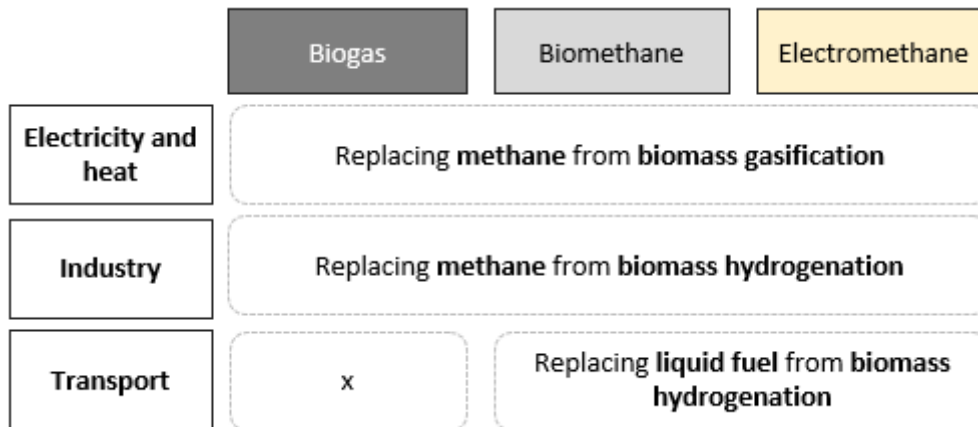


Figure 75 - Utilisation matrix with the fuels replaced in each energy sector in the 2050 scenario [81].

As such, Figure 76 illustrates that using biogas and biomethane as a replacement for upgraded syngas in the power plants has the lowest total biomass consumption among the tested alternatives. All the scenarios bring savings in dry biomass consumption between 5% and 16% in comparison to the reference scenario. These savings connect with the fuels displaced. In the case of biogas for power and heat, the saved dry biomass is larger than the inputted biogas feedstock. Higher biomass consumption is found when replacing hydrogenated fuels as in industry and transport. Overall results indicate that the electromethane scenarios have the highest primary energy supply due to the higher share of wind in the system. Even though the electromethane scenarios use lower amounts of biogas feedstock due to hydrogen addition, in the overall energy system picture, these do not use significantly less dry biomass than the biogas and biomethane scenarios. The energy system effects explain this result, where even if biogas feedstock is used more efficiently in the methanation unit, dry biomass is used in other parts of the energy system to fulfil other demands. Even though the total biomass consumption is higher in the biogas and biomethane scenarios, the overall primary energy supply is reduced compared to the electromethane scenarios due to the lower wind power capacity needed in the system [81].

Renewable fuels in the Danish energy system

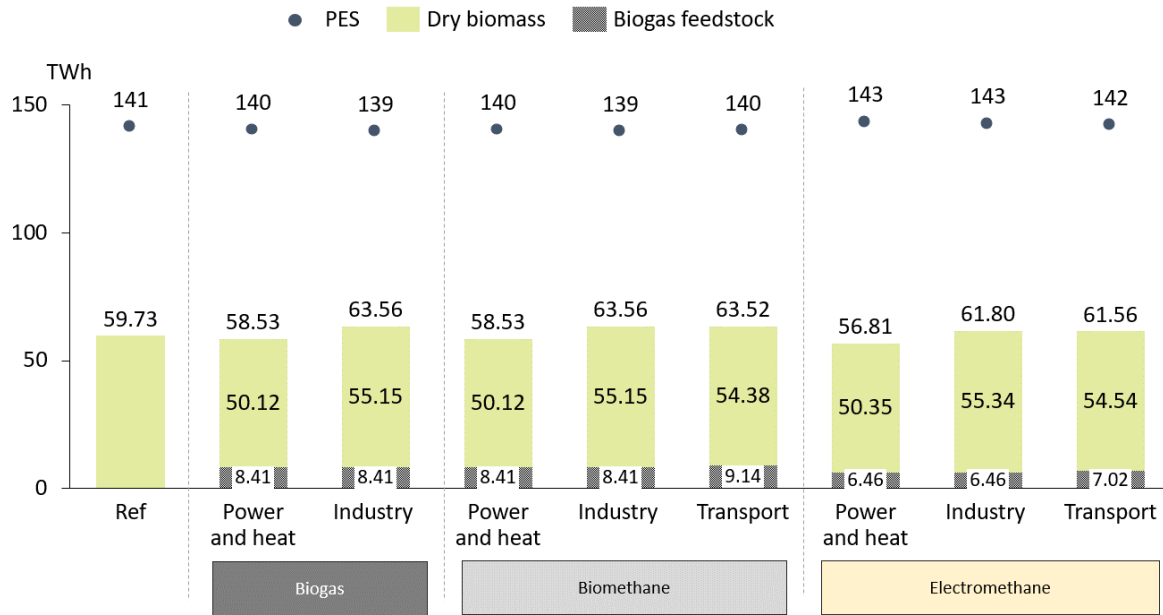


Figure 76 - Primary energy supply for the different scenarios including dry biomass and biogas supply [81]

The benefit of using biogas or biomethane for power and district heat and industry is also reflected for the energy system costs. Figure 77 illustrates that the most considerable cost reductions occur when biogas and biomethane replace gasified and hydrogenated biomass when dry biomass costs are 6 EUR/GJ. The eight scenarios with four different biogas feedstock cost levels include the handling costs. The results are presented as a marginal cost difference from the reference scenario that has no biogas utilised in the system. It is to be noted that in reality only part of the gas demand in the industry can be substituted with biogas; therefore, this specific scenario is not necessarily fully representative, but it was used to illustrate the utilisation costs. The transport sector also shows reductions, but the replacement of expensive CO₂-electrofuels mostly gives these.

Renewable fuels in the Danish energy system

Marginal system cost difference [M€]	Biogas		Biomethane			Electromethane			Low
	Electricity and heat	Industry	Electricity and heat	Industry	Transport	Electricity and heat	Industry	Transport	
Biogas feedstock prices [€/GJ]	0	-133	-174	-107	-147	-171	51	8	-20
	4.5	3	-38	29	-12	-33	155	112	87
	5.2	24	-16	50	10	-11	171	128	104
	5.9	46	5	72	31	11	188	145	121
Displacing	Gasified biomass	Gasified biomass + H ₂	Gasified biomass	Gasified biomass + H ₂	Liquid bio-electrofuels	Gasified biomass	Gasified biomass + H ₂	Liquid bio-electrofuels	High

Figure 77 - The marginal cost difference to the reference scenario for utilisation of biogas in different parts of the energy system with different levels of manure costs with fixed biomass price of 6 EUR/GJ [81].

The increase in biomass price makes the prioritisation of different forms of biogas more complicated, though still with a similar overall trend. Biogas matches better with electricity and heat generation, a result which also aligns with the biomass consumption of these scenarios in comparison to others as illustrated before in Figure 78. Once purifying biogas to biomethane, transport sector shows the highest savings, but these are similar to the biogas scenarios. The difference between the costs in some of the cases is almost negligible, making it difficult to conclude the preferred applications from a cost perspective. Considering dry biomass consumption as the primary consideration factor, then biogas should be the first choice for power and heat generation.

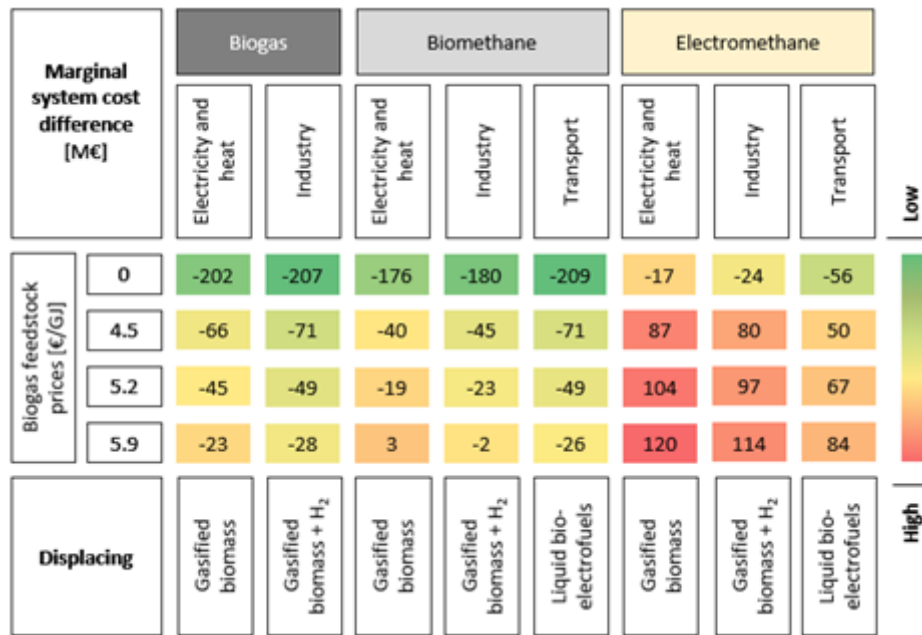


Figure 78 - The marginal cost difference to the reference scenario for utilisation of biogas in different parts of the energy system with different levels of manure costs with fixed biomass price of 8 EUR/GJ [81].

7.2.1.2 Section conclusions

The power and heat sector are the most advantaged by the use of biogas or biomethane to replace upgraded syngas due to the low biomass consumption and low energy system costs. Using a gaseous fuel instead of biomass directly in power production allows for more efficient use of biomass in more flexible units that can operate on a stop/start basis [53]. In the industry sector, the solution is interchangeable with the power and heat sector if replacing the same type of fuel. The argument of using biogas in the industry grows higher if the cost of dry biomass is on the upper level as it proves more resilient to increased biogas feedstock prices. As for power and heat, biomethane should be preferred after biogas, if that is a requirement in the industrial processes.

The use of electromethane as a replacement for natural gas remains an expensive option, and this is reflected in the fuel prices. Figure 79 illustrates the cost components for electromethane starting from the 2050 price level using offshore wind and a break-even price with the natural gas price. Only with low-cost electricity and low investments in biogas plants, electrolysis and methanation, may allow the price of electromethane to match an approximate price level for natural gas today. Increasing the price for any of the components makes this fuel more expensive than natural gas. More details of this analysis can be found in [81].

Renewable fuels in the Danish energy system

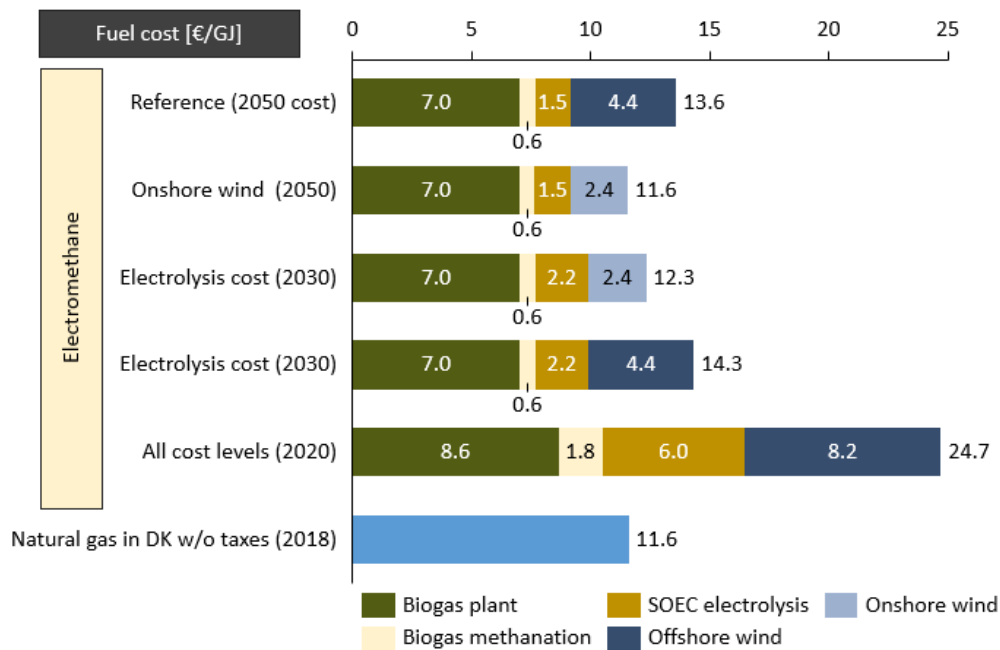


Figure 79 - Fuel cost sensitivity analysis with different cost parameter variations. The costs do not include the biogas feedstock, hydrogen storage or compression costs [81].

7.2.2 Role of biomass gasification in the energy system

The next part of this analysis inquires the role of biomass gasification in the energy system. Gasification is the process where woody biomass, straw or any other lignocellulosic material is gasified in the presence of oxygen or steam to produce syngas. Syngas can be then upgraded to grid quality for combustion in power plants or used to produce electrofuels. In the IDA, ST and GCA scenarios both solutions are used, where biomass supplies a part of the transport demands, while another share of biomass is used for power production, albeit in significantly different shares in each scenario and year analysed. In the IDA scenario, both biomass and CO₂ hydrogenation pathways are used to produce methanol for road transport and shipping and methanol-to-jet fuel for aviation. In the GCA and ST scenarios, the CO₂ hydrogenation is not used; instead, the scenarios assume that a part of the transport fuels come from imports. The Energinet scenarios also assume a lower production of electrofuels compared to IDA, mainly due to the high level of electrification. It is for these reasons that the IDA2050 scenario is found suitable for this analysis and is used further in this chapter.

The context of biomass use is broad, as potentially a large part of it may be necessary for supplying transport demands, where a variety of fuels and fuel production pathways exist. Other solutions exist that include methane, ethanol, gasoline, ammonia or Fischer-Tropsch liquids. Except for ethanol and ammonia, all fuels can be produced from biomass with or without hydrogen enhancement (biofuels or bio-electrofuels) or combining a source of carbon with electricity to produce CO₂-electrofuels. In a parallel analysis, Korberg et al. [82] analyses the feasibility of biomass gasification in connection with three fuel production pathways, namely methanol synthesis, Fischer-Tropsch synthesis and methanation for the Danish energy system in 2050. The analysis compares the fuels produced through biomass hydrogenation and CO₂ hydrogenation

while also including the jet-fuel demands, as shown in Figure 80. Six “extreme” scenarios are produced, where the three primary fuels (methanol, FT liquids and methane) are produced either via biomass hydrogenation or via CO₂ hydrogenation. Besides, for each of the primary fuels, aviation fuel production pathways are included. The reference scenario from which the six “extreme” scenarios are derived from is a variant of IDA2050, and it described accordingly in [82].

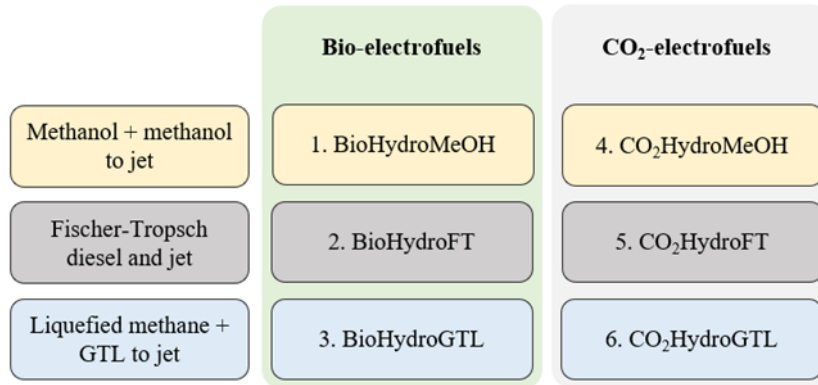


Figure 80 - The three primary fuels produced through biomass hydrogenation and CO₂ hydrogenation along with their respective jet fuel production pathways [82]

Put side by side, the results in the six “extreme” scenarios indicate different capacity and resource utilisations that differ based on the carbon resource used (biomass or CO₂) and by pathways. Using any of the CO₂-electrofuels to supply the transport demands requires 50-60% more offshore wind capacity than the bio-hydrogenation pathways, as illustrated in Figure 81. Another observation relates to the type of fuels produced in the pathways, where among the bio-electrofuels, the offshore wind capacities are similar, so producing methanol, FT liquids or methane has roughly the same effect. The differences appear when producing CO₂-electrofuels, which require significantly more electricity to achieve the same effect. As such, there are approximately 2,000 MW in favour of CO₂HydroMeOH pathway compared to the most wind intensive pathway, the CO₂HydroCH₄. The CO₂HydroFT finds itself in between the two.

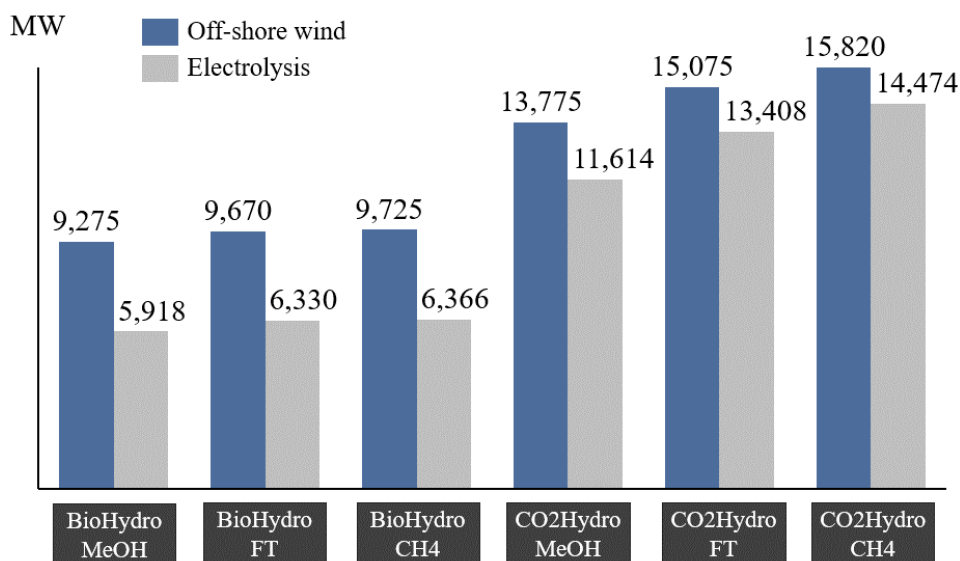


Figure 81 - Wind and electrolysis capacity differences relative to the reference scenario [82].

Regarding the electrolysis capacities, these follow the same trend as offshore wind, with electrolysis capacities 95-145% larger for CO₂-electrofuels than for bio-electrofuels. The differences between the two types of electrofuels are significant. As in the case of offshore wind capacities, the electrolysis capacities for bio-electrofuels are similar, but differences occur between the end-fuels, with CO₂HydroCH₄ requiring the largest electrolysis capacities, about 3,000 MW more than the CO₂HydroMeOH pathway. As in the case of offshore wind, the CO₂HydroFT finds itself between the other two pathways.

Gasifying biomass to produce all the fuel demands requires more than a third additional dry biomass than the CO₂ hydrogenation at 30-45% difference (Figure 82). The BioHydroMeOH pathway has the lowest biomass consumption, with 18% higher biomass consumption for the FT pathway and 35% more biomass for the methane pathway. In regards to the biomass gasification for power generation, the results in Figure 82 show approximately the same amount of gasified biomass for power generation across all three bio-electrofuels, indicating that the choice of fuel syntheses does not influence the operation of the power plants. However, it does influence the capacity of offshore wind and electrolysis, as shown in Figure 81.

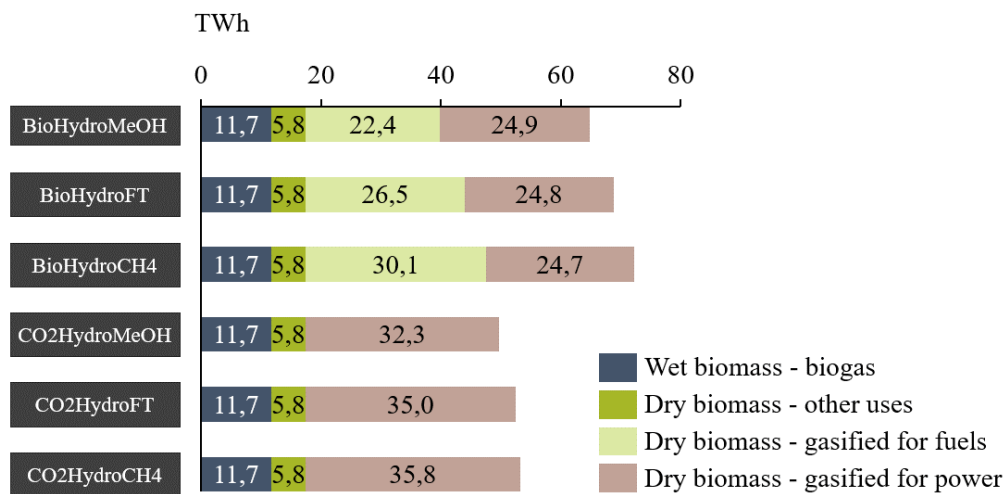


Figure 82 - Total biomass consumption in the analysed scenarios [82]

The choice of technologies and fuel production pathways influences the total cost of the energy system. A significantly larger capacity of wind and electrolysis is required to produce CO₂-electrofuels, although the production of these fuels does not use biomass directly, but can use biomass indirectly for power generation as in the case of the Danish models. An overview of the primary energy supply and energy system costs in Figure 83 shows the increased overall fuel consumption for the CO₂ hydrogenation scenarios that account for approximately 30% more wind production to supply the same transport demands. The overall energy system costs reflect this being 1-1.2 B EUR higher for CO₂-electrofuels pathways due to the additional wind, electrolysis and hydrogen storage in the energy systems.

Renewable fuels in the Danish energy system

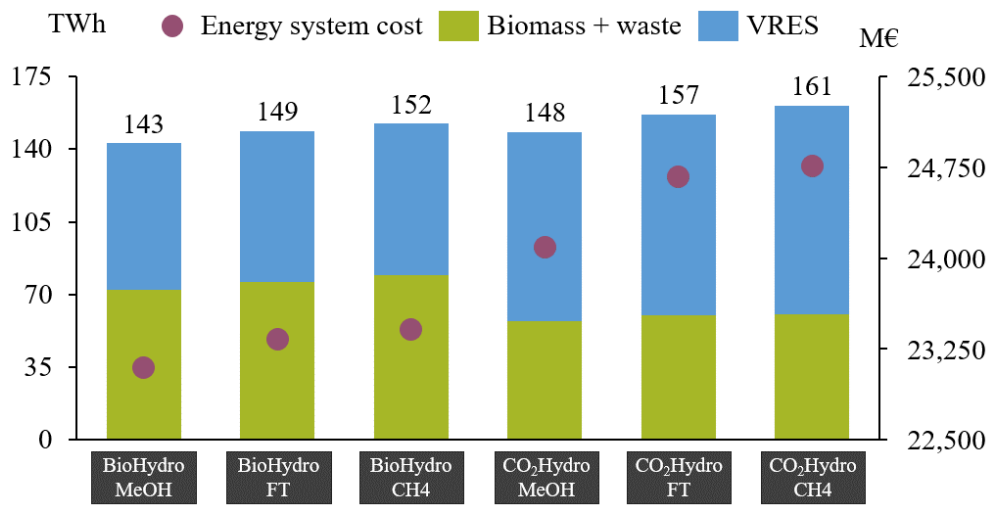


Figure 83 - Primary energy supply and total energy system cost differences [82]

As an extension, the role of biomass gasification and syngas is analysed from a market economic perspective. The goal is to understand what the energy system effects are when the scenario is tested only with biomass gasification and hydrogenation opposed to one with only CO₂ hydrogenation. In the reference model for this analysis, the market simulation strategy in EnergyPLAN is used for IDA 2050, where biomass gasification and CO₂ hydrogenation produce almost equal shares of the electrofuel demands. In these scenarios, the fuel prices vary from low, medium, and high, and electricity prices in the five levels from 16 EUR/MWh up to 77 EUR/MWh.

The results show that in all cases, the scenarios with bio-electrofuel production show significantly lower total energy system costs than the CO₂-electrofuel scenarios due to the lower demands for electricity production and electrolysis. However, the use of biomass resources varies throughout the scenarios, in a market context, dependent on the price of electricity and biomass. As such, the BioHydroX variant with the lowest electricity price (16 and 31 EUR/MWh) do not use any biomass for the production of electricity (syngas in power plants) even with the lowest costs for fuels but choose to import low-cost electricity. Once the electricity price is raised at 47 EUR/MWh, then the system starts producing electricity from biomass, at which moment the biomass price determines the amount of biomass used for electricity production. The CO₂HydroX scenarios start producing electricity from biomass at an electricity price of 31 EUR/MWh, but only with medium and high prices for biomass, due to the larger size of the electricity sector in the CO₂Hydro scenarios, where more electricity is needed to achieve the same effect. The BioHydro scenarios are more electricity-efficient than the CO₂HydroX, even though the transport demands are supplied with the same end-fuels.

Once the price of electricity is increased to 62 and respectively 77 EUR/MWh, more biomass is used to supply the internal demands. Table 12 presents the overview of the biomass consumption, electricity imports and exports.

Table 12 - Biomass for electricity and electricity imports/exports

Scenarios	Biomass for electricity (TWh)		Electricity Imports (TWh)		Electricity Exports (TWh)	
	BioHydro	CO ₂ Hydro	BioHydro	CO ₂ Hydro	BioHydro	CO ₂ Hydro
16-low	0.0	0.0	16.73	23.14	6.62	11.33
16-medium	0.0	0.0	16.98	23.29	6.61	11.30
16-high	0.0	0.0	17.18	23.50	6.64	11.38
31-low	0.0	7.8	14.34	9.25	7.06	11.74
31-medium	0.0	2.2	15.92	21.89	6.86	11.49
31-high	0.0	0.5	16.41	27.72	6.65	11.43
47-low	16.1	27.3	6.26	9.68	7.92	12.44
47-medium	6.3	18.1	10.69	14.21	7.30	12.03
47-high	0.0	9.9	13.66	18.16	7.03	11.75
62-low	33.1	37.7	1.51	6.13	11.82	14.83
62-medium	22.1	31.5	4.04	7.99	8.71	12.89
62-high	12.3	23.8	7.99	11.42	7.61	12.20
77-low	44.3	46.4	1.08	5.69	16.93	18.35
77-medium	35.0	39.9	1.36	6.04	12.63	15.31
77-high	25.3	33.6	3.04	7.31	9.33	13.28

7.2.2.1.1 Methane gas storages

Gas storages may have a different role and size in the future energy systems where no natural gas is used. The results of the part analysis for methane storage are connected to the biomass consumption for electricity production and the electricity imports/exports in Table 12. The need for gas storages may vary in different market situations, with different fuel and electricity prices. As such, using the low and high electricity and fuel prices in the market simulations can allow an overview of the potential future size of methane storage, in the context where all synthetic gas (biogas and syngas) is upgraded for grid quality. Table 13 illustrates the potential storage sizes for all the market scenarios in 2050, showing that lowest electricity price defines the smallest gas storage in the CO₂Hydro scenarios due to the reduced amounts of gas in the energy system and because electricity imports balance the energy system. Using 31 EUR/MWh electricity triggers the production of upgraded syngas for electricity production for the CO₂Hydro scenarios with low fuel costs, but the storage size required decreases once the fuel costs increase. In the case of BioHydroX scenarios, the opposite occurs, where the more expensive the fuel is, the more of it is stored. The price of 47 EUR/MWh causes the energy system to use upgraded syngas in the BioHydroX scenarios, where low fuel costs determine higher upgraded syngas production and more extensive gas storage, but where a high fuel cost determines 0 syngas production and hence smaller storage. The higher electricity prices determine high syngas production and hence most considerable gas storage requirements for both the BioHydroX and the CO₂Hydro scenarios, with minor differences between them.

Table 13 - Gas storage size and net charge/discharge capacities in the different market scenarios for IDA 2050

Scenarios	Gas storage size (GWh)		Net max capacity "+" charge and "-" discharge	
	BioHydro	CO ₂ Hydro	BioHydro	CO ₂ Hydro
16-low	4.75	1.32	777	397
16-medium	4.77	1.35	776	391
16-high	4.75	1.34	778	397
31-low	3.12	3.95	1186	-307
31-medium	3.93	2.25	885	222
31-high	4.57	1.5	798	388
47-low	4.82	4.33	-205	-2142
47-medium	4.03	4.57	725	-1289
47-high	2.72	4.29	1316	-504
62-low	4.89	4.04	-1806	-3242
62-medium	4.93	4.36	-768	-2556
62-high	4.67	4.47	156	-1823
77-low	4.62	3.91	-2869	-3972
77-medium	4.89	4.07	-1988	-3710
77-high	4.95	4.31	-1075	-2754

7.2.2.2 Section conclusions

This section illustrates the effects of utilising biomass gasification in the energy system of Denmark in both a technical and market simulation. The technical simulation highlights that biomass gasification has the potential to use available resources more efficiently, here referring to wind and biomass compared to an energy system which does not utilise this resource. Unlike CO₂-electrofuels that need large amounts of hydrogen to produce fuels, biomass contains both carbon and hydrogen molecules, allowing for reduced hydrogen consumption and effectively lower electricity consumption, the largest cost component of such fuels, also illustrated in Figure 84.

Renewable fuels in the Danish energy system

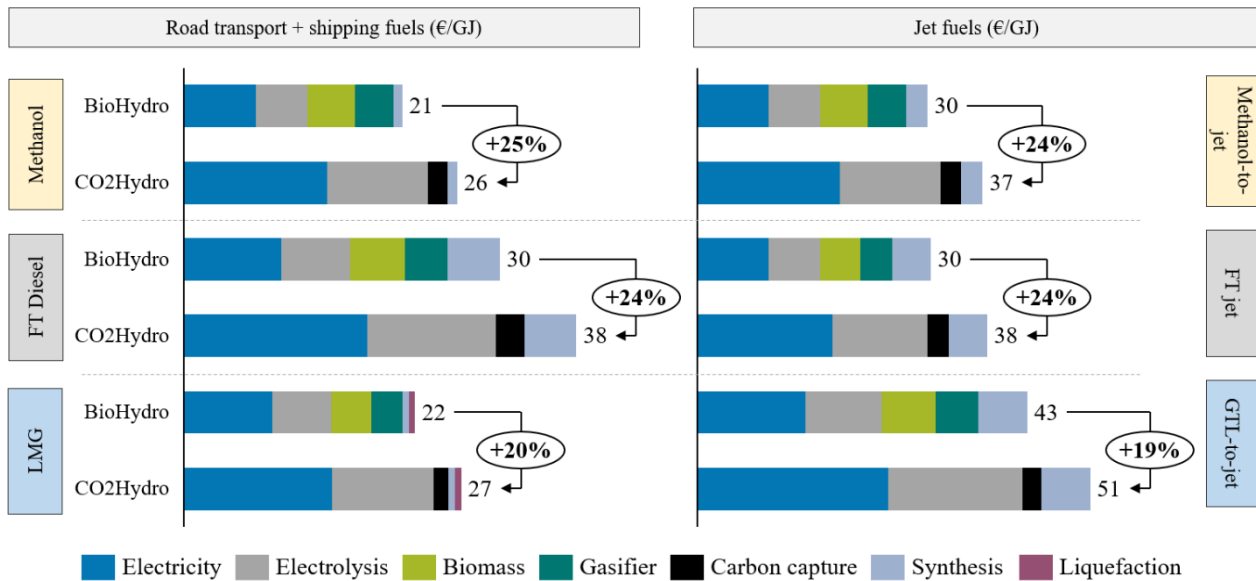


Figure 84 - Fuel prices for the six pathways split between road transport + shipping on the left and aviation on the right. Electricity price is based on offshore wind investments, while the electrolysis has an efficiency of 69% and includes a 30% overcapacity with 48h of hydrogen storage [82]

The BioHydroX variants require less electricity production compared to the CO₂HydroX variants due to the reduced demands for fuel production. The electricity production starts at a higher electricity price for the BioHydroX variants compared to the CO₂HydroX that produce electricity when using the 31 EUR/MWh price level, affecting the potential size of the gas storage, as the internal production is utilised more efficiently.

The multiple simulations demonstrate the importance of biomass gasification in the operation of energy systems, making it a key component as long as the biomass availability is considered. The biomass resources for Denmark can peak at approximately 200 PJ/year (or 56 TWh) [83], while the BioHydroX variants use 65-72 TWh/year so that a combination CO₂-electrofuels will be necessary for the future. Within the prospect of biomass sustainability, but often neglected in energy system analyses, is the issue of soil management. Along with the production of syngas, biochar (ash) results as a co-product, but to this date, it is not considered a valuable output. Efforts have been put so far on maximising the carbon conversion to syngas. However, gasifiers can be adjusted to leave more carbon in the biochar, an essential aspect as biochar contains stable carbon, more stable than the carbon in biomass, and it can be used as a method to restore the carbon balance in the soil while also acting as a method for carbon sequestration [84].

Considering the aspects of energy efficiency, biomass limitations and costs, we find that biomass gasification combined with methanol production as primary fuel should be prioritised for the transport sector where electrification is not possible. CO₂-electrofuels may be an add-on technology combined with carbon capture and utilisation from the remaining large carbon emitters to produce high value-added fuels, such as for aviation. A balance between producing fuels for transport and syngas for power production should be found, as the low-cost renewable fuel options for electricity generation is more reduced than for the transport sector.

7.2.3 Electrolyser flexibility

Besides their role in the production of electrofuels, the electrolyzers and related hydrogen storage may also have the potential of balancing the electricity grid. By using electricity from RES in times of high wind and

solar production, the electrolysers can store it as hydrogen in steel tanks or caverns for later use in the fuel production syntheses. For flexible operation, the total capacity of installed electrolysis needs to be larger than the minimum capacity to produce the necessary hydrogen each year. In other words, the lower the full-load hours of operation for electrolysers is achieved, the higher the flexibility.

A condition for using the additional electrolysis capacity is the presence of storages or flexible production units at each component of the fuel production process, from electrolysis and gasifier/carbon capture to fuel syntheses. The most common way of achieving flexibility is through hydrogen storage, while carbon capture or fuel synthesis is more challenging to operate flexibly, due to limitations as high operating temperatures or catalyst issues [67].

In the IDA 2050 scenario, the electrolysis capacity is seized to 100% of the minimum capacity, virtually double the minimum capacity with sizeable internal fuel production, and the hydrogen storage is sized to contain seven days' worth of hydrogen for fuel synthesis. Such parameters make the IDA2050 suitable for making electrolysis capacity and hydrogen storage variations, given that all fuel production is achieved internally.

In the first part of the analysis, the buffer and hydrogen storage capacities are varied from 0-100% to understand the system behaviour with the extremes. The results in Figure 85 show that the lowest energy system costs occur when using between 6,800 and 7,200 MW of electrolyser (60-70% buffer capacity) and approximately 300-400 GWh of hydrogen storage.

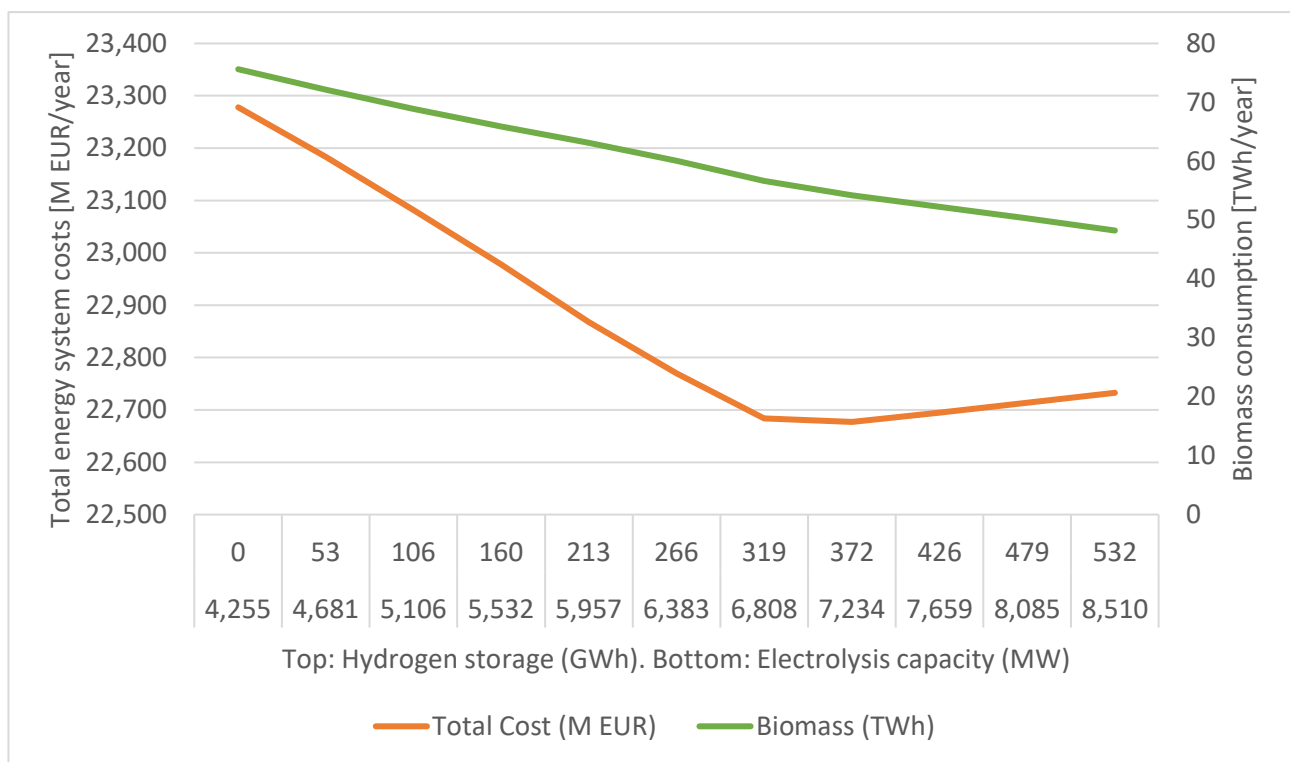


Figure 85 - Electrolysis buffer capacity and hydrogen storage with variations from 0 to 100% for electrolysis and 0 to 7 days of hydrogen storage.

In the next steps, the hydrogen storage is eliminated while keeping the upper range of electrolysis buffer capacity. In these results, independent of the hydrogen storage capacity, biomass consumption occurs at the

lowest with the largest electrolysis capacity. The reason is that the IDA model in EnergyPLAN assumes a level of flexibility in the production of fuels via the CO₂ hydrogenation pathway, allowing the electrolysis to produce more fuel when high wind production occurs. This setting “blinds” the user from understanding what the recommended level of hydrogen storage is, as flexibility occurs at two points in the fuel production process. However, as explained above, this situation may not be possible. The CO₂ hydrogenation flexibility is eliminated to overcome this issue, with the result of increased biomass consumption (gasified biomass used in power plants) and the reduction in installed offshore wind capacity (to keep the CEEP at the same level as before).

With the new setup, the upper range of buffer capacity for electrolysis is kept, from 6,500 to 8,500 MW which represents between 50 and 100% of the minimum capacity needed to produce hydrogen. The hydrogen storage capacity is varied between 100 and 600 GWh to find out the biomass consumption and total energy system costs.

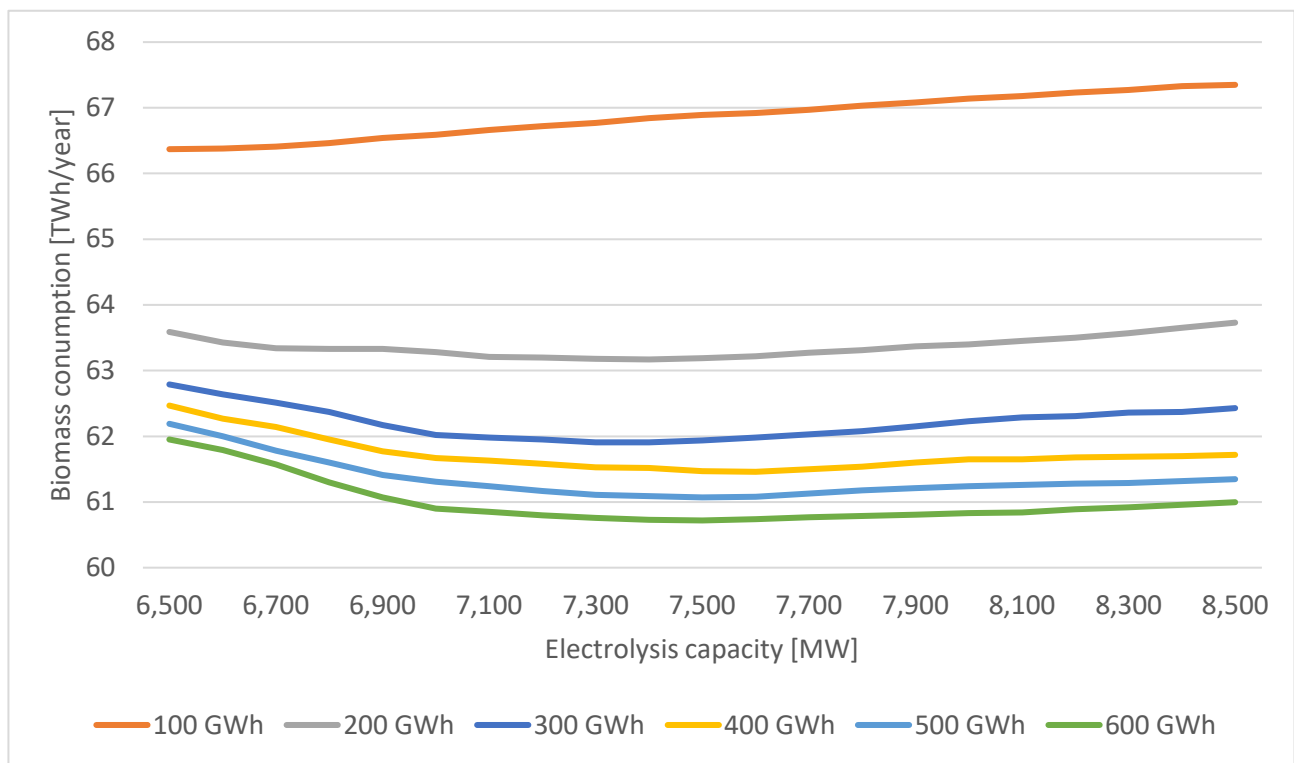


Figure 86 - Biomass consumption with different hydrogen storage sizes

The results in Figure 86 show that the amount of hydrogen storage can influence biomass consumption. In this context, 100 GWh of H₂ storage has the highest biomass consumption of all scenarios, whereby increasing the electrolysis capacity also increases biomass consumption. Implementing 200 GWh of H₂ storage shows significant improvements in the amount of biomass consumed, but once using more than 300 GWh, the biomass savings are modest. For this context, the optimal electrolysis capacities vary between 7,000 and 7,500 MW, which accounts between 3,600 and 4,000 full load hours (66-76% of the minimum capacity).

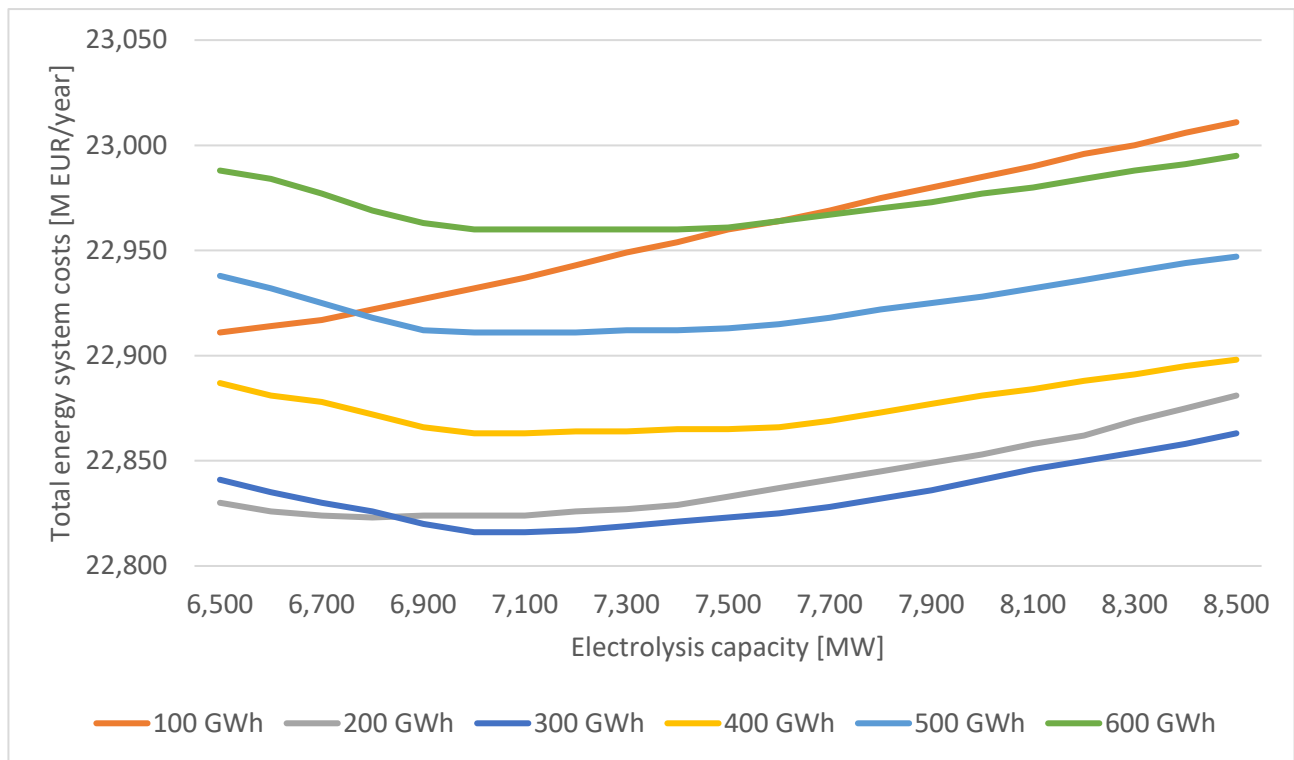


Figure 87 - Total energy system costs with varying electrolyses capacities and hydrogen storage

Regarding energy system costs, the results show that 100 GWh storage may allow low costs with reduced buffer capacities of electrolysis. However, the costs increase linearly once more electrolysis capacity is added, as the energy system uses more power plants to make up for intermittent operation of VRE. Using 200 GWh of H₂ storage makes a massive difference compared to the previous step, reducing the energy system costs significantly. Using 300 GWh H₂ storage shows the lowest cost, but by a small margin compared to using 200 GWh. What is above 300 GWh shows increasing costs, indicating that around 300 GWh of hydrogen storage is sufficient to achieve both the low costs and low biomass consumption. This value is indicative, as it is also dependent on the cost of storing hydrogen. Considering a higher cost for hydrogen storage may well indicate that the lowest energy system costs occur below 300 GWh.

The exact capacity of electrolysis and the amount of hydrogen storage are eventually a matter of system and plant design, where the choice of hydrogen storage and electrolysis capacity must relate to the availability of biomass and the willingness to pay for additional hydrogen storage capacity. The massive savings in biomass and energy system costs are finally the result of any flexibility, either the one achieved through hydrogen storage or dynamic carbon capture and fuel syntheses, which may potentially be more cost-effective if implemented, as hydrogen is an expensive fuel to store on its own. The inclusion of any dynamic behaviour can enable these to use more VRE and less electricity used from other, more expensive producers/imports.

7.2.3.1 Balances between electrification and electrofuels in transport

As explained in Section 7.1, the production of renewable fuels and electrofuels, in particular, must be seen in conjunction with the other technologies and infrastructures in the energy system where energy efficiency is critical. In the transport sector, it is a fact that electric vehicles are 3-5 times more efficient than internal

combustion engines, especially when accounting for the electrofuel production losses. Even though electrification should always have priority in a renewable energy system where the resources are scarce, it is not always possible to electrify all transport modes. Such transport modes require a high-density fuel and are represented by long-distance heavy-duty road transport, deep-ocean shipping, and aviation. For the other modes of transport, electrification is technically viable even with today’s technology. However, if more can be electrified, then this has a direct effect on the energy system. This part analysis illustrates the effects of increasing the share of transport electrification by 50% in the scenario named High EV. Figure 88 shows that increasing the level of transport electrification in IDA2050 with technical simulation does not alter the total biomass consumption significantly but does show a reduced primary energy supply by approximately 9 TWh compared to the reference scenario. More electricity from power plants is necessary to manage the new demand from electric vehicles, despite reducing the demand for biomass gasification and hydrogenation. The constant biomass consumption between the reference scenario and the scenario with increased EV share relates to the fuel production pathways replaced. In the High EV scenario, we replace equal shares of both bio-electrofuels and CO₂-electrofuels with increased electrification, so the direct effect on biomass is reduced. The effect on energy system costs is reduced, due to the reduction of the installed capacity of offshore wind.

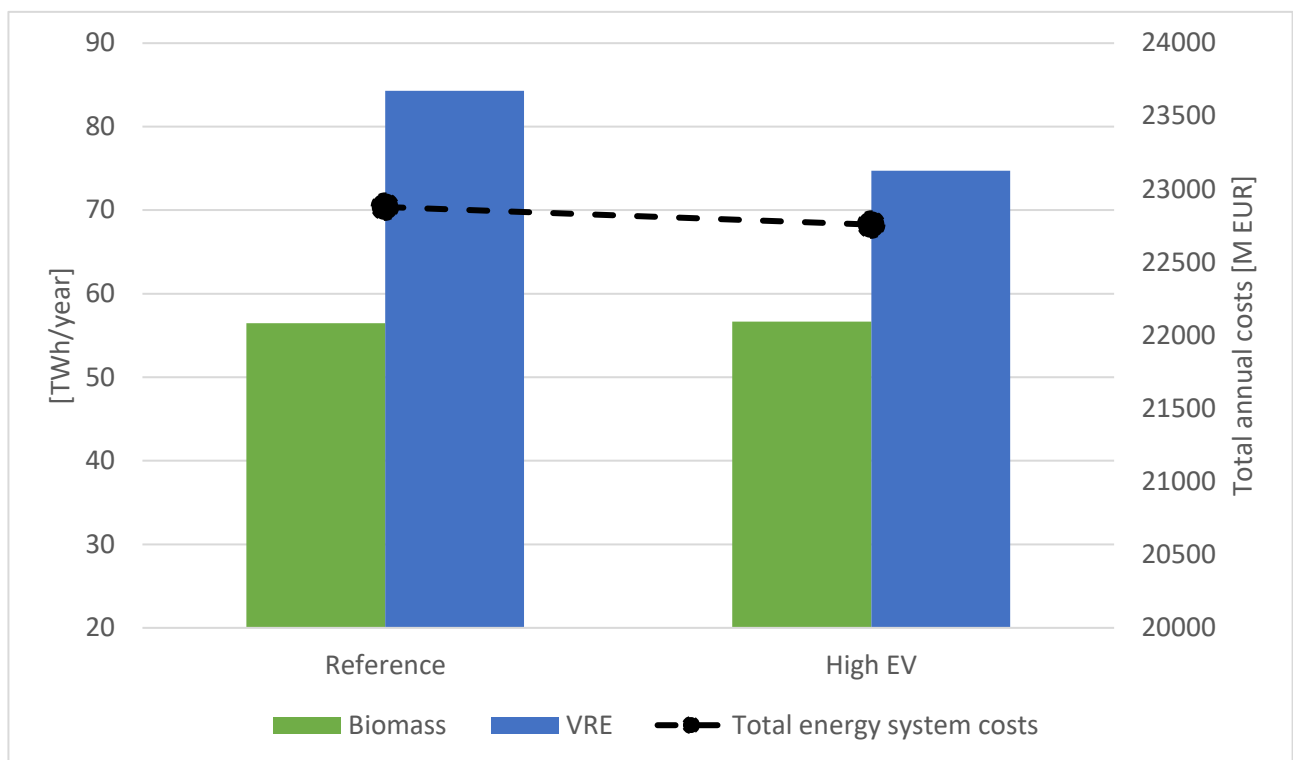


Figure 88 - Energy system effects of increasing and decreasing the level of electrification in transport, assuming that vehicle costs are the same.

In modified versions of IDA2050, we verify the effects of replacing only bio-electrofuels or only CO₂-electrofuels with the same increased share of electric vehicles, to understand the effects on biomass and VRE consumption. The new results in Figure 89 demonstrate biomass savings of almost 5 TWh compared to the reference, while the VRE production reduces by another ~2TWh, despite the increase in the fuel consumed by power plants.

Renewable fuels in the Danish energy system

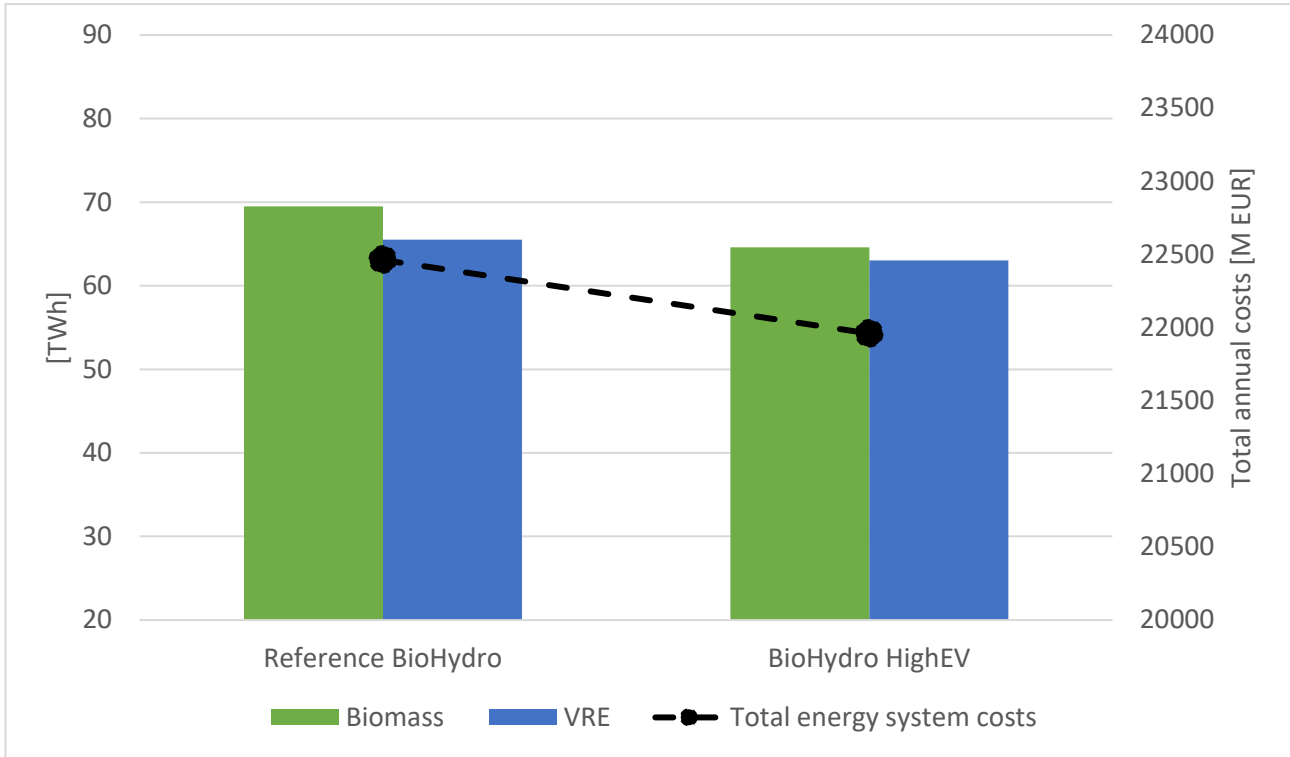


Figure 89 - Energy system effects of increasing and decreasing the level of electrification in a scenario where only bio-electrofuels are replaced with +50% EV demand

Similar effects can be observed in Figure 89, where a considerable reduction in the production of VRE can be observed, at ~11 TWh of electricity but more modest reductions in biomass ~2.5 TWh. This difference occurs as CO₂-electrofuels use significantly more electricity to obtain the same effect as bio-electrofuels.

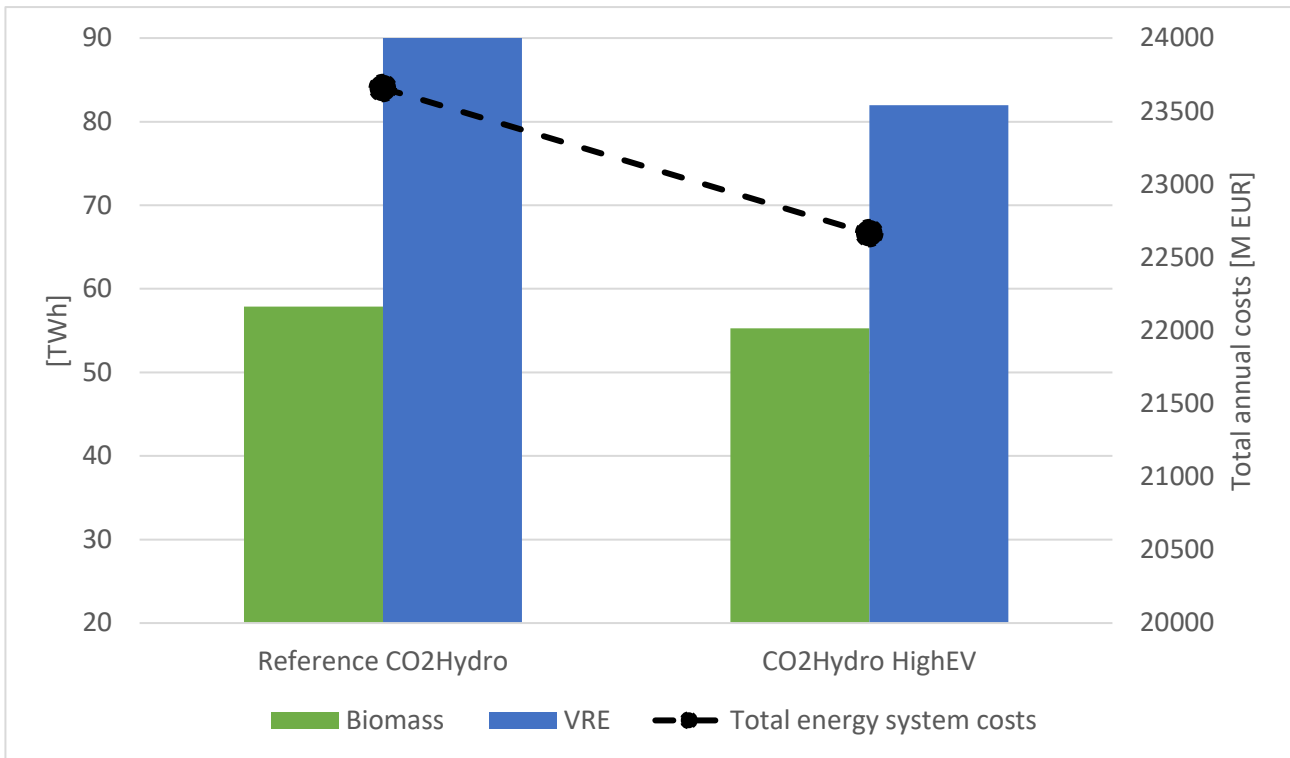


Figure 90 - Energy system effects of increasing and decreasing the level of electrification in a scenario where only CO₂-electrofuels are replaced with +50% EV demand

7.3 Conclusions on renewable fuels

The results of the renewable fuels analysis highlighted the critical role these fuels can have in the energy system. However, producing any type of liquid or gaseous renewable fuels is more expensive and less efficient than electrification, so one of the conclusions of this analysis is that the priority should always be given to electrification. Electrofuels can supply the demands in the parts of the transport sector where direct electrification cannot. Despite their increased resource consumption (compared to direct electricity use), electrofuels may also act as a mean to store electricity as chemical energy. The results of the analysis show considerable potential for flexible operation using a few full load hours for electrolyzers and sufficient hydrogen storage. There is a balance between achieving high flexibility while keeping the energy system costs down, and the results of the analysis find that between 2.5 and 4 days of hydrogen storage combined with up to 4,000 full load hours of operation for electrolyzers are necessary for a Danish energy system with internal fuel production (as IDA2050), depending on the cost of hydrogen storage.

Regarding the type of fuels needed in the energy system, for the transport sector, it is found that liquid electrofuels show lower energy system and fuel costs than gaseous electrofuels. Electromethanol shows the lowest energy system and costs, albeit similar to electromethane, until the cost of vehicles is added in the equation. Methanol, in general, has greater flexibility regarding storage and readiness to be upgraded to other fuels, namely jet fuels, which is a more complicated and energy-intensive process if it would be produced from methane. Fischer-Tropsch fuels may be an alternative if methanol-to-jet fuel pathways will not show sufficient technological maturity in the future.

Renewable fuels in the Danish energy system

The production process of electrofuels has a large impact on the energy system. Producing bio-electrofuels from biomass gasification indicates more significant overall biomass consumption but increases the efficiency of the energy system compared to producing CO₂-electrofuels. That occurs as bio-electrofuels use both electrolytic hydrogen and the hydrogen in biomass, while CO₂-electrofuels can use only electrolytic hydrogen. Both types of electrofuels are necessary for the future energy system despite the increased costs of CO₂-electrofuels as the fuels are limited by biomass availability and available CO₂-sources.

Biomass is pivotal to balance the future energy system in the times when VRE are not sufficient. The results of the analysis indicate that syngas from biomass gasification will be a crucial fuel in combination with biogas both used for power, heat, or industrial purposes, at lower costs than electrofuels. Biogas should always have priority due to the lower cost, but since the agricultural sector outputs limit it, it must be complemented by syngas. Biogas and syngas should both be used without further processing if possible, due to the high additional costs for upgrading, in dedicated grids or locally. Figure 91 illustrates the levelised cost of electricity for flexible power plants using any of the for types of fuels at different feedstock prices compared to the cost of electricity produced from offshore wind, indicating that the least amounts of syngas should be used for the purpose of electricity generation. In addition, maximising on the use of lower-cost bio-electrofuels has reduced use of biomass for electricity generation allowing the energy system to be more resilient to external electricity prices.

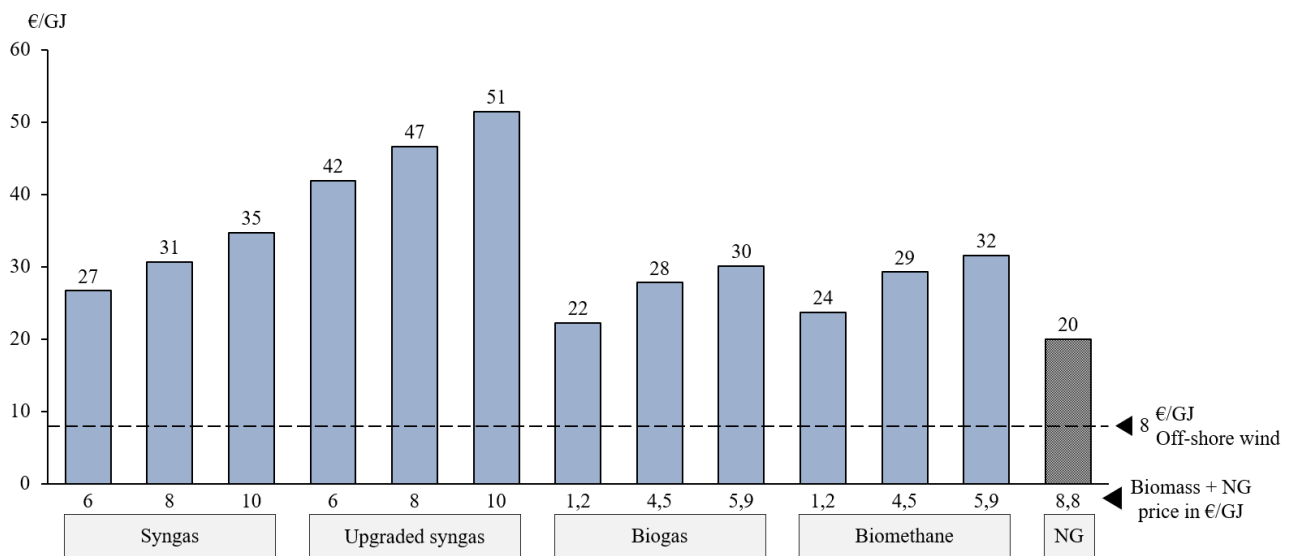


Figure 91 - The levelized cost of electricity for a CCGT in extraction mode with 4,000 hours of operation hours with different fuels options and prices, compared to the offshore wind electricity price, all at 2050 cost and efficiency levels [82]

Considering the aspects of energy efficiency, biomass limitations and costs, it is concluded that biomass conversion technologies and electrofuels will have a crucial role in future energy systems while keeping within the boundaries of sustainable biomass resources. Biomass gasification combined with methanol production as primary fuel should be prioritised for the transport sector where electrification is not possible. CO₂-electrofuels may be an add-on technology combined with carbon capture and utilisation from the remaining large carbon emitters to produce high value-added fuels, such as for aviation. A balance between producing fuels for transport and syngas for power production should be found, as syngas and biogas are the few fuel options for electricity, heat, or industry sectors in a 100% renewable energy system for Denmark.

8 Recommendations of the transition towards the 100% renewable-based Danish energy system

In this report, different options for a future Danish energy system based on 100% renewable energy are analysed. The effects on the medium-term are also analysed to investigate the transition process better. The goal of these analyses is to provide recommendations to the transition towards 100% renewable energy. Three different future energy system scenarios are utilised to analyse it. From Energinet’s “System Perspective 2035” two scenarios are used, Sustainable transition (ST) and Global climate action (GCA), and alongside these the IDA scenario from “IDA’s Energy Vision 2050” is used. Each of these scenarios has an energy system model for 2035 and 2050. Alongside these, a scenario for the Danish energy system in 2020 is created for comparison. All scenarios are set up into a modelling testbed, where the method for simulation and costs are set so that they are similar between the different scenarios, as to make the scenarios as comparable as possible without changing the capacities installed or the energy demands given in the scenarios. In the modelling testbed, the scenarios and changes to the scenarios are investigated using different future price projections for international electricity market prices and fuel prices. The analyses are categorised into four different parts: operational analyses, electrification, heating, and renewable fuels.

8.1 Operational analyses

First, the different scenarios’ hourly operation is analysed without changes to the installed technologies and demands. Here it is found that towards 2050, where all the three scenarios go to 100% renewable energy in Denmark, the yearly operation of the CHP and power plants decrease, even in the scenarios with a significant decrease in the CHP and power plant capacity. The analyses reveal that even though the yearly operation of these plants is reduced, there are still hours where the full capacity is needed, indicating that the value of these plants shifts from being the energy produced to instead be the capacity offered. This effect is most significant in 2050, though the shift can also be seen in 2035. This indicates that markets must adapt to this change in value, as a given capacity of CHP or power plant will require more income per amount of electric energy produced to cover the long-term marginal costs. Another option is to consider these units as part of the support system or infrastructure needed in integrated renewable energy systems.

A similar situation can be seen concerning using the transmission line capacity to surrounding countries for maintaining the Danish electricity system balance. Going towards 2050 the transmission line capacity is used for import in fewer hours, however, in the hours it is utilised more of the capacity is utilised. There is also a difference in the scenarios, where ST and GCA rely heavily on the import of electricity for electricity system balance, as they have a relatively small capacity of flexible CHP and power plants, the IDA scenario has significant more CHP and power plant capacity and less transmission line capacity. Table 14 shows the transmission line capacities and flexible CHP and power plant capacity in the different scenarios.

Table 14 – Flexible thermal electric capacity in each scenario

	2020	2035			2050		
[GW]	Ref. model	ST	GCA	IDA	ST	GCA	IDA
Flexible thermal plants	4.55	4.14	4.16	5.53	1.87	1.98	6.00
Transmission capacity	7.10	10.40	12.70	7.10	10.40	12.70	7.10

Though the transmission line capacity for import is used more at or close to full capacity in 2050, in the IDA scenario, it is used at full capacity at around 8.5% of the year, whereas in ST and GCA scenarios it is only used for import at full capacity at around 0.1% of the year. For export of electricity the transmission line capacity is utilised more at its full capacity in the ST and GCA scenarios with the full capacity being utilised at around 1% of the year in 2050.

Looking at the peak utilisation, in the 2035 versions of the ST and GCA scenarios, the transmission line capacity is only utilised up to around 70% both for import and export of electricity, indicating that the transmission line capacity in 2035 in the ST and GCA scenarios is over-dimensioned in relation to the needs of the Danish energy system. The analyses do not include the transmission of electricity through Denmark nor potential breakdowns. The analyses indicate that the transmission line capacity is needed for balancing the electricity system, though an expansion is not needed if sufficient flexible electric capacity is maintained in the Danish energy system. Also, the results indicate that the transmission line capacity is more utilised for the needs of the Danish energy system in 2050 compared to 2035 and that the full capacity of the transmission is only needed in a small part of the year, especially in scenarios where the transmission line capacity is expanded. It should be noted that with the higher capacity of CHP and power plants in the IDA scenario, it can be operated independently of surrounding countries, but is also able to benefit considerably of the electricity trade with the surrounding countries, due to the flexible elements in the energy system design.

8.2 Electrification

Electrification is the process of satisfying end-user demands by electricity. Already many end-user demands, such as lighting, are met by electricity, though it is evident in all the scenarios that more electrification is needed in the transition towards 100% renewable energy, as the electricity demand in Denmark is set to increase from around 35 TWh/year in 2020 to 73-93 TWh/year in 2050, depending on the scenario. Examples of this include extensive use of electric HPs in both individual and DH areas, a transportation sector based predominantly on electricity and electrofuels, and electrolyzers for hydrogen production. The reason for the increased electrification of the energy demands is the significant increase in VRE, such as wind power and PV, that goes from producing around 20 TWh/year in 2020 to around 67-8 TWh/year in 2050, depending on the scenario. From an energy production perspective, in all scenarios, the major expansion is seen in offshore wind power. With this increase in electricity demand and production, the electricity sectors role in the future 100% renewable energy system becomes even more important and is connected to many different energy sectors. This part focus on the electrification that is not related to the transport sector or the space heating and hot water consumption, as these parts are analysed in relation to the *Renewable fuels and Heating* section, respectively. As such, the electrification focus on the following parts:

- Industry electrification
- Electricity demand flexibility
- Grid-scale electricity storage

In the analyses of the electrification part, it is found that systems with low internal dispatchable power production capacity are more sensitive to external markets and external electricity prices. This is important as future electrification of the energy system is inherently connected to both internal electricity production capacity and transmission capacity. If the Danish energy system has low internal dispatchable power production, then it must also be expected that the costs of the energy system will vary to a greater extent from year

to year, depending on the seasonal and yearly fluctuations of market prices. Similarly, the advantage and optimal level of electrification is also more uncertain in such an energy system.

Looking at electrification of the Danish industrial process heat demands, it is found that direct electrification of industrial process heat demands should be favoured over a fuel shift to hydrogen-based processes, due to lower costs of the energy system and higher energy system efficiency with direct electrification. From an energy system perspective, direct use of hydrogen for industrial processes should only be used where no alternative solution exists. This does not include potential gains from biproducts of the electrolyses, such as O₂. In the Renewable Fuels chapter, it is found that from an energy system perspective electromethane is not a good solution either, due to the high costs and low efficiency of the energy system, but more options are available as biogas/biomethane. Though, it should be noted that the underlying assumptions for this analysis are connected with some uncertainty, and future research should follow up on this as the technologies mature and more specific applications for hydrogen-based processes in industry are determined.

Flexible electricity demand occurs when the time of use of the demand can be shifted to another time or even be replaced by other energy sources than electricity. All the scenarios introduce many new flexible electricity demands, such as electric vehicles, electrolysis, and HPs with connection to heat storages. Here the focus is on flexibility of the traditional electricity demand, being the electricity demand for households and the industry sector excluding individual HPs. This can, e.g. be flexible use of washing machines or refrigeration. In all the scenarios, around 10% of the traditional electricity demand is set as flexible, with most of it being flexible within one day. It is found in the analyses that increased flexibility of the traditional demand can contribute to increased integration of VRE, especially for energy systems with few flexibility options in the internal electricity production mix, being the ST and GCA scenarios, as the flexibility helps reduce electricity demand in peak hours. The effects of this are limited to the available capacity and this type of flexibility only allows the demands to be moved within a relatively short period, typically max. a week, and flexibility for longer periods is also needed. Uncertainties remain in relation to the actual achievable flexibility amount and the potential investment costs needed. However, the energy markets should be designed in such a way as to allow for flexible use of electricity by consumers, especially in scenarios with high reliance on import and export of electricity, as a supplement to the new flexible electricity demands.

Grid-scale batteries are often discussed as a way of allowing for higher utilisation of VRE in the electricity system. Li-ion batteries are discussed as they have seen a decrease in price, as they are the main components of many appliances and electric vehicles, and they have a relatively high round-trip efficiency compared to other battery technologies. In this study, the use of li-ion batteries as grid-scale batteries is found to be a very costly approach for integrating VRE, even with the most optimistic price projections for li-ion batteries. Li-ion batteries concerning grid-scale applications may be useful for other purposes such as back-up capacity or short-term balancing and frequency regulation if no other cheaper alternatives exist, though in an integrated future Danish energy system it is unlikely that the need for such grid-scale batteries is relevant to any significant extent. Li-ion batteries does, however, serve an essential role in relation to the transport sector to allow for the use of electricity in vehicles.

Other grid-scale battery technologies are being developed worldwide, and some of these might allow for a significantly lower investment cost than li-ion or other batteries. In this some preliminary analyses are done for one of these technologies, being high-temperature rock bed storages. In rock bed storages electric energy is used to heat rocks to high temperatures that allow for the extraction of the energy stored as heat to be

used in a turbine. The technology is still in development, and the potential implementation potentials in the energy system requires more research, though here the technology is tested to be used as a supplement for combined cycle gas turbines that includes a steam turbine component. With the application of the rock bed storages examined here, the competitiveness is largely dependent on the ability to replace fuel usage in CHP and power plants in the system, which, inherently, has fewer and fewer operation hours. In these preliminary analyses, high-temperature rock bed storages seem economic feasible as a cheaper alternative to li-ion batteries for electricity storage, allowing low investment cost short-term storage of energy from VRE. However, this needs to be verified in future analyses as improved technical data becomes available, and as such, the results presented in this is related to a high degree of uncertainty.

8.3 Heating

The heating sector here is defined as all space heating demands, hot water consumption demands, and losses in the DH systems. As such, industrial process heat demands are not investigated in this section.

In all the scenarios the heating sector continues to be an important energy sector in Denmark, as even with heat savings that are introduced in the different scenarios the heat demand still accounts for a large share of the end-user demand. The scenarios also include changes to the heating solutions used, both in relation to the production of heat but also for storing heat. In this, the following are analysed:

- Heat savings
- Individual heating solution incl. heat storages
- DH production technologies (CHP units and HPs)
- DH storages

Heat savings are found to reduce the total annual costs of the energy system, mainly by reducing fuel consumption, but only up to a certain point, thereafter the costs of introducing more heat savings are higher than the gains. In relation to energy system costs the optimal level of heat savings was found to be approximately 32% compared with the average consumption per m² in 2010. Heat savings also result in reduced biomass consumption, which continues to decrease linearly as more heat savings are implemented. The reduction in biomass consumption is mainly due to decreased biomass consumption for DH fuel boilers and biomass gasification, as the individual biomass boilers only account for relatively small energy demand. As the biomass amount that can be used for a sustainable future energy system is likely limited, heat savings until around 42% could provide reductions in biomass consumption at a relatively low cost. Going from 32% to 42% heat savings increases the total annual cost of the system by less than 0.2% of total annual costs of the IDA scenario for 2050 but reduces the biomass consumption by about 3.5% of the total biomass consumption of the IDA scenario for 2050. As such, introducing heat savings is important for both reducing the total annual costs of the energy system but also to reduce the biomass consumption of the energy system.

In the three scenarios, the technology for individual heating is changed from being delivered by fuel boilers to instead being mostly delivered by electric-driven HPs. This decision is analysed, and it is found that if biomass boilers were used instead of electric-driven HPs for individual heating, both the biomass consumption and the total annual cost of the energy system would increase. This conclusion is regardless of analysed energy system scenario as well as the market prices for fuel and electricity. It is also found that solar thermal heating can help to reduce the use of biomass of the energy system, though solar thermal is only expected

to be a supplement. As such, individual heating should mainly be supplied by electric-driven individual HPs in a future energy system based on 100% renewable energy. Having individual heat storage technologies in connection with the HPs and solar thermal can reduce the biomass consumption of the energy system but only up to a certain point, depending on the amount of other flexible electricity demands in the scenario, though research has shown that from an energy system cost perspective only low-cost individual storage options should be considered.

Currently, CHP plants deliver a large share of the Danish DH production. However, as shown in the operational analyses the operation of CHP plants is expected to be different in future 100% renewable energy systems. As such, it is analysed how different thermal plant technologies would affect the energy system. The tested technologies are combined cycle gas turbine (CCGT), simple cycle gas turbine (SCGT) and large Wood Pellets Extraction plant. It is found that the high electric efficiency of the CCGT provides the system with the lowest costs and lowest biomass consumption. The CHP capacity's effect on the biomass consumption has also been tested, by removing the CHP capacity in the test of the three technologies, thereby changing them from CHP plants to power plants. Though the overall differences are minor, it is found that the use of large-scale CHP units might not be necessary for keeping the biomass consumption at low levels, as long as the replacement power plants are highly efficient and sufficient other low-biomass consuming heat sources for DH, such as HPs, are available in the system.

Electric-driven HPs are extensively used for DH production in all the scenarios. The effect of these units is analysed by increasing and decreasing the capacity of these with different replacement technologies. This is first tested without changing the capacities of the other DH technologies, and here it is found that for the total annual costs the optimal sizing is very dependent on the price projections used. In relation to biomass consumption, increasing the HP capacity decreases the biomass consumption, though the effect of this is most significant at low levels of HP capacity. Similar conclusions are found if geothermal heat is used as a replacement technology for DH production, though the variations due to price projections are reduced by having this technology as replacement. In the ST2050 and GCA2050 scenarios, which have the lowest capacities of large-scale CHP capacity, using CHP capacity as a replacement for the DH-based HPs is also investigated. Here it is found that CHP capacity as a replacement only reduces the total annual costs of the energy system at high electricity market price levels, except if increased CHP capacity in Denmark would result in reduced capacity of transmission line capacity, in which case the CHP would also reduce the total annual costs at the medium electricity price levels. As such, having internal flexible CHP capacity in the energy system seems to make it possible to reduce the total annual costs of the energy system, and as shown in other analyses it would also stabilise the total annual costs in relation to changing international electricity market prices.

Short-term storages for DH are also analysed, and it is found that in most cases, completely removing short-term storages increases both the total annual costs and biomass consumption of the energy system. For total annual costs, this is less obvious in scenarios with many different DH production technologies and high levels of excess and geothermal heat, where the value of short-term storages is lower. Though, the analyses presented in this are expected to undervalue the benefits that short-term storages can have locally and in the daily operation of individual DH systems.

8.4 Renewable fuels

Going towards 100% renewable energy also means changing the fuels used to renewable alternatives. Some is expected to be changed to direct electrification, such as electric vehicles and electric-driven HPs, however, fuels will likely still be needed in the energy system for different purposes, such as long-haul road transport, maritime navigation, aviation or gas for CHP, power plants or industry. In this part, the roles of the following are analysed:

- Electrolyser flexibility
- Electrification and electrofuels in transport
- Biogas
- Dry biomass

Generally, it is found that producing any type of liquid or gaseous renewable fuels is more expensive and less efficient than direct electrification, so priority should always be given to direct electrification where possible. Electrofuels can supply the demands in the parts of the transport sector where direct electrification cannot. Despite their increased resource consumption (compared to direct electricity use), electrofuels may also act as a mean to store electricity as chemical energy using electrolyses. The results of the analysis show considerable potential for flexible operation of electrolyzers, provided sufficient hydrogen storage exists. The need for hydrogen storage in this respect means that there is a balance to strike between the flexible operation of electrolyzers and the energy system costs. In this, it is found that the optimal balance for the Danish energy system is somewhere between 2.5 and 4 days of hydrogen storage combined with an electrolyser capacity of about 1.6-1.7 times the minimum needed capacity. This result is especially sensitive to the cost of hydrogen storage.

For the transport sector, it is found that liquid electrofuels provides lower energy system and fuel costs than gaseous electrofuels. Electromethanol has the lowest energy system costs, albeit similar to the results for electromethane until the cost of vehicles is added in the equation. Generally, methanol provides greater flexibility regarding storage and readiness to be upgraded to other fuels, namely jet fuels, which is a more complicated and energy-intensive process if it would be produced from methane. Fischer-Tropsch fuels may be an alternative if methanol-to-jet fuel pathways does not show sufficient technological maturity in the future.

The production process of electrofuels has a large impact on the energy system. Producing bio-electrofuels from biomass gasification indicates more significant overall biomass consumption but increases the efficiency of the energy system compared to producing CO₂-electrofuels. That occurs as bio-electrofuels use both electrolytic hydrogen and the hydrogen in biomass, while CO₂-electrofuels can only use electrolytic hydrogen. Both types of electrofuels are necessary for the future energy system despite the higher costs of CO₂-electrofuels as the fuels are limited by biomass availability and available CO₂-sources.

Biomass is pivotal to balance the future energy system in the periods when VRE is not sufficient. The results of the analysis indicate that syngas from biomass gasification can be a crucial fuel in combination with biogas both used for power, heat, or industrial purposes, at lower costs than electrofuels. Biogas should always have priority due to the lower cost, but since the agricultural sector outputs limit biogas, it must be complemented by syngas. Biogas and syngas should both be used without further processing if possible, due to the high

additional costs for upgrading, in dedicated grids or locally. In addition, maximising on the use of lower-cost bio-electrofuels has reduced use of biomass for electricity generation allowing the energy system to be more resilient to external electricity prices.

It is found that biomass conversion technologies and electrofuels will have a crucial role in future energy systems but that the biomass consumption should be kept within the sustainable boundaries. Biomass gasification combined with methanol production as primary fuel should be prioritised for the transport sector where electrification is not possible. CO₂-electrofuels may be an add-on technology combined with carbon capture and utilisation from the remaining large carbon emitters to produce high value-added fuels, such as for aviation. A balance between producing fuels for transport and syngas for power production should be found, as syngas and biogas are the few fuel options for electricity, heat, or industry sectors in a 100% renewable energy system for Denmark.

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10 Appendix A – ST2035

Input	Value	Reference	Note
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Electricity production

Fixed electricity demand (TWh/year)	37.3	[85]	The fixed electricity demand includes the “classic demand” and the electricity demand for process heat pumps.
Flexible electricity demand (1 day) (TWh/year)	0	[85]	
Max-effect for flexible electricity demand (1 day) (MW)	-		

Wind (onshore)

Capacity (MW)	5,414	[85]	
Annual production (TWh)	17.16	[85]	

Offshore Wind

Capacity (MW)	4,546	[85]	Including offshore and near shore wind power capacity
Annual production (TWh)	19.98	[85]	Including offshore and near shore wind power production

Photo Voltaic

Capacity (MW)	3,450	[85]	
Annual production (TWh)	4.16	[85]	

Thermal power production

Large CHP units condensing power capacity (MW)	2,111	[85]	The difference between the condensing capacity and the central CHP capacity is unknown, and it is here assumed to be equal.
Large CHP units condensing power efficiency	32.8%	[85]	The difference between the condensing efficiency and the CHP capacity is unknown, and it is here assumed to be equal. The efficiency is annual average.

District heating

Decentralised district heating

District heating production (TWh/year)	21.68	[85]	
Fuel boiler capacity (MW)	7,345		Assumed to be 120% of the simulated peak demand.
Fuel boiler efficiency	95.1%	[85]	

Small-scale CHP - Electric capacity (MW)	2,029	[85]	Excl. waste incineration (waste incineration capacity is assumed to be 400 MW based on yearly production and assumed 8000 full load hours). Total incl. Waste from [85].
Small-scale CHP - Electric efficiency	32.4%	[85]	The value represents the annual average efficiency.
Small-scale CHP - Thermal capacity (MW)	2,348	[85]	Based on average efficiencies and the electric capacity excl. waste incineration)
Small-scale CHP - Thermal efficiency	37.5%	[85]	The value represents the annual average efficiency.
Fixed boiler share	30.5%		Used to replicate the yearly productions from Energinets simulation
Grid loss	15%	[85]	
Thermal storage capacity (GWh)	15	[85]	The total DH storage capacity is 30 GWh, and it is here assumed that it is split 50/50 between central and decentral plants.
Solar thermal input (TWh/year)	0.51	[85]	
Industrial CHP heat produced (TWh/year)	1.91	[85]	Includes all district heating produced from “Process – Kraftvarme” and “Process Fjernvarme”, excl. heat coming from waste incineration the share of which is found based on assumed yearly efficiencies.
Industrial CHP electricity produced (TWh/year)	0.939	[85]	Includes all electricity produced from “Process – Kraftvarme”, excl. electricity coming from waste incineration the share of which is found based on assumed yearly efficiencies
Industrial CHP heat demand (TWh/year)	1.04	[85]	Includes district heating demand for industries.
Compression heat pump electric capacity (MW)	27	[85]	
Compression heat pump COP	3.5	[85]	Yearly average COP
Compression heat pump maximum share of load	0.025		Used to replicate the DH production from the Energinet simulations.
Electric boiler capacity (MW)	333	[85]	Divided between central and decentral based on total capacity and operation in each category.
Industrial excess heat (TWh/year)	0.77	[85]	The category “Overskudsvarme” from [85].

Central district heating

District heating production (TWh/year)	13.09	[85]	The amount of district heating produced by central plants.
Fuel boiler capacity (MW)	4,435		Assumed to be 120% of the simulated peak demand.
Fuel boiler efficiency	90.1%	[85]	

Large CHP - Electric capacity (MW)	2,111	[85]	The difference between the condensing capacity and the central CHP capacity is unknown, and it is here assumed to be equal
Large CHP - Electric efficiency	32.8%	[85]	The difference between the condensing efficiency and the central CHP capacity is unknown, and it is here assumed to be equal
Large CHP - Thermal capacity (MW)	3,224	[85]	
Large CHP - Thermal efficiency	50.1%	[85]	
Fixed boiler share	3%		Used to replicate the yearly productions from Energinets simulation
Grid loss	15%	[85]	
Thermal storage capacity (GWh)	15	[85]	The total DH storage capacity is 30 GWh, and it is here assumed that it is split 50/50 between central and decentral plants.
Industrial CHP heat produced (TWh/year)	0	[85]	
Industrial CHP electricity produced (TWh/year)	0	[85]	
Industrial CHP heat demand (TWh/year)	0	[85]	
Compression heat pump electric capacity (MW)	468	[85]	
Compression heat pump COP	3.5	[85]	Yearly average COP
Compression heat pump maximum share of load	1		Used to replicate the DH production from the Energinet simulations.
Electric boiler capacity (MW)	304	[85]	Divided between central and decentral based on total capacity and operation in each category.

Fuel Distribution and Consumption

Fuel Distribution for Heat and Power Production

These relations indicate for each of the plant type the fuel mix for used for each plant type (Coal / Oil / Gas / Biomass).

Small-scale CHP units	0 / 0.01 / 2.45 / 2.91	[85]	Based on fuel consumption from [85]. Oil is fixed.
Large CHP units	0 / 0 / 1.35 / 7.77	[85]	Based on fuel consumption from [85].
Boilers in decentralised district heating	0 / 0.193 / 3.88 / 5.44	[85]	Based on fuel consumption from [85]. Oil is fixed.
Boilers in central district heating	0 / 0.02 / 0.31 / 0.08	[85]	Based on fuel consumption from [85]. Oil is fixed.
Condensing operation of large CHP units	0 / 0 / 1.35 / 7.77	[85]	Based on fuel consumption from [85].
Condensing power plants	-	[85]	Based on fuel consumption from [85].

Additional fuel consumption (TWh/year)

Coal in industry	0	[85]	
Oil in industry	0.86	[85]	Includes gas consumption of “Process – Kraftvarme”, “Process – Fjernvarme” and “Process – Varme”
Gas in industry	9.32	[85]	Includes gas consumption of “Process – Kraftvarme”, “Process – Fjernvarme” and “Process – Varme”
Biomass in industry	2.74	[85]	Includes gas consumption of “Process – Kraftvarme”, “Process – Fjernvarme” and “Process – Varme”
Coal, various	0	[85]	
Oil, various	0	[85]	
Natural gas, various	0	[85]	

Transport

Conventional fuels (TWh/year)

JP (Jet fuel) - fossil	11.1	[85]	
Diesel - fossil	9.73	[85]	
Petrol - fossil	9.22	[85]	
Grid gas	1.82	[85]	
JP (Jet fuel) - biofuel	0	[85]	
Diesel - biofuel	0	[85]	
Petrol - biofuel	0	[85]	
JP (Jet fuel) - electrofuel	1.23	[85]	
Diesel - electrofuel	0	[85]	
Petrol - electrofuel	3.35	[85]	

Electricity (TWh/year)

Electricity - dump charge	1.72	[85]	
Electricity – smart charge	6.14	[85]	All electric cars are assumed to be smart charge (not V2G), based on mail from Anders Bavnhøj
Max. share of cars during peak demand	20%	[1]	IDA2050 number
Capacity of grid to battery connection (MW)	15,584	[2][1][85]	Based on page 39 in “Systemperspektiv 2035 – Baggrundsrapport” and the IDA2050 scenario.
Share of parked cars grid connected	70%	[1]	IDA2050 number
Efficiency (grid to battery)	90%	[1]	IDA2050 number

Battery storage capacity (GWh)	13.5	[2][1][85]	Based on page 39 in “Systemperspektiv 2035 – Baggrundsrapport” and the IDA2050 scenario.
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Waste conversion

Waste incineration in decentralised district heating

Waste input (TWh/year)	10.25	[85]	Incl. waste used for DH CHP, DH boilers, and process heat.
Thermal efficiency	73.7%	[85]	
Electric efficiency	21.9%	[85]	

Waste incineration in central district heating

Waste input (TWh/year)	0.4	[85]	
Thermal efficiency	97.6%	[85]	
Electric efficiency	0	[85]	

Individual heating

Coal boilers

Fuel consumption (TWh/year)	0	[85]	
Efficiency	-		

Oil boilers

Fuel consumption (TWh/year)	0	[85]	
Efficiency	-		

Gas boilers

Fuel consumption (TWh/year)	6.43	[85]	
Efficiency	100%	[85]	Annual average value
Solar thermal input (TWh/year)	0	[85]	

Biomass boilers

Fuel consumption (TWh/year)	8.43	[85]	
Efficiency	89%	[85]	Annual average value
Solar thermal input (TWh/year)	0	[85]	

Heat pumps

Heat demand (TWh/year)	4.69	[85]	
COP	3.28	[85]	Annual average value
Solar thermal input (TWh/year)	0	[85]	

Electric heating

Heat demand (TWh/year)	0.57	[85]	Based on electricity demand for individual electric heating
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Biogas production

Biogas production (TWh/year)	0	[85]	
Biogas upgrade to grid efficiency	-		

Gasification plant

Biomass input (TWh/year)	0	[85]	
Electricity share	-		
Steam share	-		
Steam efficiency	-		
Coldgas efficiency	-		
DH central share	-		

Electrolysers

Electrolyser capacity (MW-e)	0	[85]	
Electrolyser efficiency (Biomass hydrogenation)	-		
Electrolyser efficiency (Biogas hydrogenation)	-		

Biomass hydrogenation

Liquid fuel output (TWh/year)	0	[85]	
Liquid fuel efficiency	-		
Hydrogen share	-		
DH central share	-		

Biogas hydrogenation

Gas fuel output (TWh/year)	0	[85]	
Gas fuel efficiency	-		
Hydrogen share	-		
DH decentral share	-		

Electricity exchange

Transmission line capacity (MW)	10,435	[85]	
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Balancing

CEEP regulation strategy	2,3,4,5	[1]	IDA2050 strategy
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Distributions

The distributions do not influence the total annual energy, but allocates the total onto each hour of the year.

Input for distribution	Reference	Note
Electricity demand	[1]	IDA2050 distribution
Individual heat demand	[1]	IDA2050 distribution
Individual solar thermal	[1]	IDA2050 distribution
District heating demand	[1]	IDA2050 distribution
District heating solar thermal	[1]	IDA2050 distribution
Offshore Wind	[1]	IDA2050 distribution
Onshore Wind	[1]	IDA2050 distribution
Photo Voltaic	[1]	IDA2050 distribution

11 Appendix B – ST2050

Input	Value	Reference	Note
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Electricity production

Fixed electricity demand (TWh/year)	38.85	[85]	The fixed electricity demand includes the “classic demand”, minus the 10% that are assumed flexible within 1 day, the electricity used for biofuelsynthesis and the electricity demand for process heat pumps.
Flexible electricity demand (1 day) (TWh/year)	3.82	[85]	10% of the classic electricity demand is flexible within 1 day.
Max-effect for flexible electricity demand (1 day) (MW)	691	[85]	Assumed to be equal to peak demand if distribution for “classic demand” was used.

Wind (onshore)

Capacity (MW)	6,164	[85]	
Annual production (TWh)	17.72	[85]	

Offshore Wind

Capacity (MW)	8,585	[85]	Including offshore and near shore wind power capacity
Annual production (TWh)	37.23	[85]	Including offshore and near shore wind power production

Photo Voltaic

Capacity (MW)	9,850	[85]	
Annual production (TWh)	12.49	[85]	

Thermal power production

Large CHP units condensing power capacity (MW)	391	[85]	The difference between the condensing capacity and the central CHP capacity is unknown, and it is here assumed to be equal.
Large CHP units condensing power efficiency	40.4%	[85]	The difference between the condensing efficiency and the CHP capacity is unknown, and it is here assumed to be equal. The efficiency is annual average.
Capacity of large steam turbines operating on excess heat from gasification (MW)	100	[85]	A number of central steam turbines are operating on excess heat from the biomass hydrogenation. EnergyPLAN does not simulate the flows of excess heat, and as such, these units have been simulated in the “Dammed hydropower” category of EnergyPLAN, in order to adhere to the simulation logic of Energinets scenarios.

Annual electricity production by large steam turbines operating on excess heat from gasification (TWh)	0.62	[85]	A number of central steam turbines are operating on excess heat from the biomass hydrogenation. EnergyPLAN does not simulate the flows of excess heat, and as such, these units have been simulated in the “Dammed hydropower” category of EnergyPLAN, in order to adhere to the simulation logic of Energinets scenarios.
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District heating

Decentralised district heating

District heating production (TWh/year)	17.346	[85]	The amount of district heating produced by decentral plants.
Fuel boiler capacity (MW)	5,877		Assumed to be 120% of the simulated peak demand.
Fuel boiler efficiency	95.5%	[85]	
Small-scale CHP - Electric capacity (MW)	1,476	[85]	Excl. waste incineration (waste incineration capacity is assumed to be 160 MW based on yearly production and assumed 8000 full load hours). Total incl. Waste from [85].
Small-scale CHP - Electric efficiency	37.4%	[85]	The value represents the annual average efficiency.
Small-scale CHP - Thermal capacity (MW)	2,044	[85]	Based on average efficiencies and the electric capacity excl. waste incineration
Small-scale CHP - Thermal efficiency	51.8%	[85]	The value represents the annual average efficiency.
Fixed boiler share	37%		Used to replicate the yearly productions from Energinets simulation
Grid loss	15%	[85]	
Thermal storage capacity (GWh)	15	[85]	The total DH storage capacity is 30 GWh, and it is here assumed that it is split 50/50 between central and decentral plants.
Solar thermal input (TWh/year)	0.51	[85]	
Industrial CHP heat produced (TWh/year)	1.879	[85]	Includes all district heating produced from “Process – Kraftvarme” and “Process Fjernvarme”, excl. heat coming from waste incineration the share of which is found based on assumed yearly efficiencies
Industrial CHP electricity produced (TWh/year)	0.919	[85]	Includes all electricity produced from “Process – Kraftvarme”, excl. electricity coming from waste incineration the share of which is found based on assumed yearly efficiencies
Industrial CHP heat demand (TWh/year)	1.507	[85]	Includes district heating demand for electrolysis in decentral energy plants, and the district heating demand for industries.

Compression heat pump electric capacity (MW)	27	[85]	
Compression heat pump COP	3.5	[85]	Yearly average COP
Compression heat pump maximum share of load	0.02		Used to replicate the DH production from the Energinet simulations.
Electric boiler capacity (MW)	333	[85]	Divided between central and decentral based on total capacity and operation in each category.
Industrial excess heat (TWh/year)	0.72	[85]	The category “Overskudsvarme” from [85].

Central district heating

District heating production (TWh/year)	17.65	[85]	The amount of district heating produced by central plants.
Fuel boiler capacity (MW)	5,980		Assumed to be 120% of the simulated peak demand.
Fuel boiler efficiency	95%	[85]	
Large CHP - Electric capacity (MW)	391	[85]	The difference between the condensing capacity and the central CHP capacity is unknown, and it is here assumed to be equal
Large CHP - Electric efficiency	40.4%	[85]	The difference between the condensing efficiency and the central CHP capacity is unknown, and it is here assumed to be equal
Large CHP - Thermal capacity (MW)	393	[85]	
Large CHP - Thermal efficiency	40.6%	[85]	
Fixed boiler share	3%		Used to replicate the yearly productions from Energinets simulation
Grid loss	15%	[85]	
Thermal storage capacity (GWh)	15	[85]	The total DH storage capacity is 30 GWh, and it is here assumed that it is split 50/50 between central and decentral plants.
Industrial CHP heat produced (TWh/year)	0.504	[85]	Heat output from the central steam turbines that are operating on excess heat from the gasification of biomass.
Industrial CHP electricity produced (TWh/year)	-	[85]	
Industrial CHP heat demand (TWh/year)	-	[85]	
Compression heat pump electric capacity (MW)	703	[85]	
Compression heat pump COP	3.5	[85]	Yearly average COP
Compression heat pump maximum share of load	0.5		Used to replicate the DH production from the Energinet simulations.
Electric boiler capacity (MW)	304	[85]	Divided between central and decentral based on total capacity and operation in each category.

Fuel Distribution and Consumption

Fuel Distribution for Heat and Power Production

These relations indicate for each of the plant type the fuel mix for used for each plant type (Coal / Oil / Gas / Biomass).

Small-scale CHP units	0 / 0 / 6.58 / 0.91	[85]	Based on fuel consumption from [85].
Large CHP units	0 / 0 / 0.51 / 0	[85]	Based on fuel consumption from [85].
Boilers in decentralised district heating	0 / 0.19 / 3.46 / 5.55	[85]	Based on fuel consumption from [85]. The oil demand is satisfied with electrofuels
Boilers in central district heating	0 / 0 / 0.55 / 0.02	[85]	Based on fuel consumption from [85].
Condensing operation of large CHP units	0 / 0 / 0.51 / 0	[85]	Based on fuel consumption from [85].
Condensing power plants	-	[85]	Based on fuel consumption from [85].

Additional fuel consumption (TWh/year)

Coal in industry	0	[85]	
Oil in industry	0	[85]	
Gas in industry	5.75	[85]	Includes gas consumption of “Process – Kraftvarme”, “Process – Fjernvarme” and “Process – Varme”
Biomass in industry	0	[85]	
Coal, various	0	[85]	
Oil, various	0	[85]	
Natural gas, various	0	[85]	

Transport

Conventional fuels (TWh/year)

JP (Jet fuel) - fossil	0	[85]	
Diesel - fossil	0	[85]	
Petrol - fossil	0	[85]	
Grid gas	7.29	[85]	
JP (Jet fuel) - biofuel	0	[85]	
Diesel - biofuel	0	[85]	
Petrol - biofuel	0	[85]	
JP (Jet fuel) - electrofuel	11.17	[85]	
Diesel - electrofuel	0	[85]	
Petrol - electrofuel	4.87	[85]	

Electricity (TWh/year)

Electricity - dump charge	5.37	[85]	
Electricity – smart charge	11.51	[85]	All electric cars are assumed to be smart charge (not V2G), based on mail from Anders Bavnhøj
Max. share of cars during peak demand	20%	[1]	IDA2050 number
Capacity of grid to battery connection (MW)	29,213	[2][1][85]	Based on page 39 in “Systemperspektiv 2035 – Baggrundsrapport” and the IDA2050 scenario.
Share of parked cars grid connected	70%	[1]	IDA2050 number
Efficiency (grid to battery)	90%	[1]	IDA2050 number
Battery storage capacity (GWh)	25.3	[2][1][85]	Based on page 39 in “Systemperspektiv 2035 – Baggrundsrapport” and the IDA2050 scenario.

Waste conversion

Waste incineration in decentralised district heating

Waste input (TWh/year)	2.26	[85]	Incl. waste used for DH CHP, DH boilers, and process heat
Thermal efficiency	84%	[85]	
Electric efficiency	13%	[85]	

Waste incineration in central district heating

Waste input (TWh/year)	0.34	[85]	
Thermal efficiency	97.6%	[85]	
Electric efficiency	0	[85]	

Individual heating

Coal boilers

Fuel consumption (TWh/year)	0	[85]	
Efficiency	-		

Oil boilers

Fuel consumption (TWh/year)	0	[85]	
Efficiency	-		

Gas boilers

Fuel consumption (TWh/year)	0.2	[85]	
Efficiency	100%	[85]	Annual average value
Solar thermal input (TWh/year)	0	[85]	

Biomass boilers

Fuel consumption (TWh/year)	2.64	[85]	
Efficiency	89%	[85]	Annual average value
Solar thermal input (TWh/year)	0		

Heat pumps

Heat demand (TWh/year)	11.365	[85]	
COP	3.136	[85]	Annual average value
Solar thermal input (TWh/year)	1.367	[85]	

Electric heating

Heat demand (TWh/year)	0.26	[85]	Based on electricity demand for individual electric heating
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Biogas production

Biomass input (TWh/year)	26.24	[85]	
Biogas production (TWh/year)	18.86	[85]	
Biogas upgrade to grid efficiency	100%	[85]	Based on the produced amount minus the biogas to methanation, and the amount sent to the grid
Input to gas grid (TWh/year)	17.93	[85]	Amount purified and sent to the grid

Gasification plant

Biomass input (TWh/year)	13.42	[85]	
Electricity share	1.7%	[85]	
Steam share	13%	[85]	Total efficiency from [85]
Steam efficiency	125%	[85]	Total efficiency from [85]
Coldgas efficiency	83.9%	[85]	Total efficiency from [85]
DH central share	20.3%	[85]	Heat used for water shift subtracted.

Electrolysers

Electrolyser capacity (MW-e)	823	[85]	
Electrolyser efficiency (Biomass hydrogenation)	90.5%	[85]	The electric efficiency of producing hydrogen is increased by the use of water shift in situations, where the electricity price is high. The water shift technology gets excess heat from gasification.
Electrolyser efficiency (Biogas hydrogenation)	83%	[85]	
Hydrogen storage [GWh]	3.32	[85]	Energinet utilises watershift technology to enable flexible operation of electrolysis in Sifre-Adapt. Watershift is not included in

			EnergyPLAN, and as such, this flexible operation is approximated by adding non-cost hydrogen storage to the EnergyPLAN versions. The size of the storage is set as being able to store 6 full load hours of operation.
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Biomass hydrogenation

Liquid fuel output (TWh/year)	11.12	[85]	
Liquid fuel efficiency	77.46%	[85]	
Hydrogen share	30%	[85]	
DH central share	7.3%	[85]	Heat used for central steam turbines subtracted.

Biogas hydrogenation

Gas fuel output (TWh/year)	1.18	[85]	
Gas fuel efficiency	80%	[85]	
Hydrogen share	36.5%	[85]	
DH decentral share	20%	[85]	

Electricity exchange

Transmission line capacity (MW)	10,435	[85]	
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Balancing

CEEP regulation strategy	2,3,4,5	[1]	IDA2050 strategy
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Distributions

The distributions do not influence the total annual energy, but allocates the total onto each hour of the year.

Input for distribution	Reference	Note
Electricity demand	[1]	IDA2050 distribution
Individual heat demand	[1]	IDA2050 distribution
Individual solar thermal	[1]	IDA2050 distribution
District heating demand	[1]	IDA2050 distribution
District heating solar thermal	[1]	IDA2050 distribution
Offshore Wind	[1]	IDA2050 distribution
Onshore Wind	[1]	IDA2050 distribution
Photo Voltaic	[1]	IDA2050 distribution

12 Appendix C – GCA2035

Input	Value	Reference	Note
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Electricity production

Fixed electricity demand (TWh/year)	35.28	[85]	The fixed electricity demand includes the “classic demand”, minus the 10% that are assumed flexible within 1 day, the electricity used for biofuelsynthesis and the electricity demand for process heat pumps.
Flexible electricity demand (1 day) (TWh/year)	3.72	[85]	10% of the classic electricity demand is flexible within 1 day.
Max-effect for flexible electricity demand (1 day) (MW)	638	[85]	Assumed to be equal to peak demand if distribution for “classic demand” was used.

Wind (onshore)

Capacity (MW)	5,414	[85]	Resulting capacity factor is 0.36
Annual production (TWh)	16.95	[85]	

Offshore Wind

Capacity (MW)	5,796	[85]	Resulting capacity factor is 0.51
Annual production (TWh)	25.50	[85]	

Photo Voltaic

Capacity (MW)	4250	[85]	Resulting capacity factor is 0.16
Annual production (TWh)	5.19	[85]	

Thermal power production

Large CHP units condensing power capacity (MW)	2,491	[85]	Excl. central steam turbines only operating on excess heat.
Large CHP units condensing power efficiency	48.1%	[85]	Excl. central steam turbines only operating on excess heat.
Capacity of large steam turbines operating on excess heat from gasification (MW)	100	[85]	A number of central steam turbines are operating on excess heat from the biomass hydrogenation. EnergyPLAN does not simulate the flows of excess heat, and as such, these units have been simulated in the “Dammed hydropower” category of EnergyPLAN, in order to adhere to the simulation logic of Energinets scenarios.
Annual electricity production by large steam turbines operating on excess heat from gasification (TWh)	0.57	[85]	A number of central steam turbines are operating on excess heat from the biomass hydrogenation. EnergyPLAN does not simulate the flows of excess heat, and as such, these units have been simulated in the

			“Dammed hydropower” category of EnergyPLAN, in order to adhere to the simulation logic of Energinets scenarios.
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District heating

Decentralised district heating

District heating production (TWh/year)	18.15	[85]	The amount of district heating produced by decentral plants.
Fuel boiler capacity (MW)	6150		Assumed to be 120% of the simulated peak demand.
Fuel boiler efficiency	91.7%	[85]	
Small-scale CHP - Electric capacity (MW)	1,664	[85]	Excl. waste incineration (waste incineration capacity is assumed to be 220 MW based on yearly production and assumed 8000 full load hours). Total incl. Waste from [85].
Small-scale CHP - Electric efficiency	33.2%	[85]	The value represents the annual average efficiency.
Small-scale CHP - Thermal capacity (MW)	2,621	[85]	Based on average efficiencies and the electric capacity excl. waste incineration)
Small-scale CHP - Thermal efficiency	52.3%	[85]	The value represents the annual average efficiency.
Fixed boiler share	26%		Used to replicate the yearly productions from Energinets simulation
Grid loss	15%	[85]	
Thermal storage capacity (GWh)	15	[85]	The total DH storage capacity is 30 GWh, and it is here assumed that it is split 50/50 between central and decentral plants.
Solar thermal input (TWh/year)	0.51	[85]	
Industrial CHP heat produced (TWh/year)	1.6	[85]	Includes all district heating produced from “Process – Kraftvarme” and “Process Fjernvarme”, excl. heat coming from waste incineration the share of which is found based on assumed yearly efficiencies.
Industrial CHP electricity produced (TWh/year)	0.791	[85]	Includes all electricity produced from “Process – Kraftvarme”, excl. electricity coming from waste incineration the share of which is found based on assumed yearly efficiencies
Industrial CHP heat demand (TWh/year)	2.21	[85]	Includes district heating demand for industries.
Compression heat pump electric capacity (MW)	306	[85]	
Compression heat pump COP	3.5	[85]	Yearly average COP
Compression heat pump maximum share of load	0.08		Used to replicate the DH production from the Energinet simulations.

Electric boiler capacity (MW)	21	[85]	Divided between central and decentral based on total capacity and operation in each category.
Industrial excess heat (TWh/year)	0.772	[85]	The category “Overskudsvarme” from [85].

Central district heating

District heating production (TWh/year)	18.3	[85]	The amount of district heating produced by central plants.
Fuel boiler capacity (MW)	6,200		Assumed to be 120% of the simulated peak demand.
Fuel boiler efficiency	91.3%	[85]	
Large CHP - Electric capacity (MW)	1,906	[85]	
Large CHP - Electric efficiency	39%	[85]	
Large CHP - Thermal capacity (MW)	2,404	[85]	
Large CHP - Thermal efficiency	49.2%	[85]	
Fixed boiler share	1.5%		Used to replicate the yearly productions from Energinets simulation
Grid loss	15%	[85]	
Thermal storage capacity (GWh)	15	[85]	The total DH storage capacity is 30 GWh, and it is here assumed that it is split 50/50 between central and decentral plants.
Industrial CHP heat produced (TWh/year)	0.379	[85]	Heat output from the central steam turbines that are operating on excess heat from the gasification of biomass.
Industrial CHP electricity produced (TWh/year)	0	[85]	
Industrial CHP heat demand (TWh/year)	0	[85]	
Compression heat pump electric capacity (MW)	555	[85]	
Compression heat pump COP	3.5	[85]	Yearly average COP
Compression heat pump maximum share of load	0.5		Used to replicate the DH production from the Energinet simulations.
Electric boiler capacity (MW)	465	[85]	Divided between central and decentral based on total capacity and operation in each category.

Fuel Distribution and Consumption

Fuel Distribution for Heat and Power Production

These relations indicate for each of the plant type the fuel mix for used for each plant type (Coal / Oil / Gas / Biomass).

Small-scale CHP units	0 / 0.01 / 3.47 / 3.04	[85]	Based on fuel consumption from [85]. Oil is fixed.
Large CHP units	0 / 0 / 1.46 / 11.11	[85]	Based on fuel consumption from [85].
Boilers in decentralised district heating	0 / 0.13 / 1.21 / 5.94	[85]	Based on fuel consumption from [85]. Oil is fixed.
Boilers in central district heating	0 / 0.02 / 0.28 / 0.03	[85]	Based on fuel consumption from [85]. Oil is fixed.
Condensing operation of large CHP units	0 / 0 / 1.46 / 11.11	[85]	Based on fuel consumption from [85].
Condensing power plants	-	[85]	Based on fuel consumption from [85].

Additional fuel consumption (TWh/year)

Coal in industry	0	[85]	
Oil in industry	0.43	[85]	Includes gas consumption of “Process – Kraftvarme”, “Process – Fjernvarme” and “Process – Varme”
Gas in industry	6.74	[85]	Includes gas consumption of “Process – Kraftvarme”, “Process – Fjernvarme” and “Process – Varme”
Biomass in industry	1.59	[85]	Includes gas consumption of “Process – Kraftvarme”, “Process – Fjernvarme” and “Process – Varme”
Coal, various	0	[85]	
Oil, various	0	[85]	
Natural gas, various	0	[85]	

Transport

Conventional fuels (TWh/year)

JP (Jet fuel) - fossil	11.1	[85]	
Diesel - fossil	7.82	[85]	
Petrol - fossil	9.22	[85]	
Grid gas	2.85	[85]	
JP (Jet fuel) - biofuel	0	[85]	
Diesel - biofuel	0	[85]	
Petrol - biofuel	0	[85]	
JP (Jet fuel) - electrofuel	1.23	[85]	
Diesel - electrofuel	0	[85]	
Petrol - electrofuel	3.36	[85]	

Electricity (TWh/year)

Electricity - dump charge	2.18	[85]	
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Electricity – smart charge	6.14	[85]	All electric cars are assumed to be smart charge (not V2G), based on mail from Anders Bavnhøj
Max. share of cars during peak demand	20%	[1]	IDA2050 number
Capacity of grid to battery connection (MW)	15,584	[2][1][85]	Based on page 39 in “Systemperspektiv 2035 – Baggrundsrapport” and the IDA2050 scenario.
Share of parked cars grid connected	70%	[1]	IDA2050 number
Efficiency (grid to battery)	90%	[1]	IDA2050 number
Battery storage capacity (GWh)	13.5	[2][1][85]	Based on page 39 in “Systemperspektiv 2035 – Baggrundsrapport” and the IDA2050 scenario.

Waste conversion

Waste incineration in decentralised district heating

Waste input (TWh/year)	5.18	[85]	Incl. waste used for DH CHP, DH boilers, and process heat.
Thermal efficiency	76%	[85]	
Electric efficiency	17.8%	[85]	

Waste incineration in central district heating

Waste input (TWh/year)	0.251	[85]	
Thermal efficiency	97.6%	[85]	
Electric efficiency	0	[85]	

Individual heating

Coal boilers

Fuel consumption (TWh/year)	0	[85]	
Efficiency	-		

Oil boilers

Fuel consumption (TWh/year)	0	[85]	
Efficiency	-		

Gas boilers

Fuel consumption (TWh/year)	2.84	[85]	
Efficiency	100%	[85]	Annual average value
Solar thermal input (TWh/year)	0	[85]	

Biomass boilers

Fuel consumption (TWh/year)	6.48	[85]	
Efficiency	89%	[85]	Annual average value
Solar thermal input (TWh/year)	0	[85]	

Heat pumps

Heat demand (TWh/year)	8.445	[85]	
COP	3.124	[85]	Annual average value
Solar thermal input (TWh/year)	0.41	[85]	

Electric heating

Heat demand (TWh/year)	0.287	[85]	Based on electricity demand for individual electric heating
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Biogas production

Biomass input (TWh/year)	26.24	[85]	
Biogas production (TWh/year)	18.89	[85]	
Biogas upgrade to grid efficiency	100%	[85]	
Input to gas grid (TWh/year)	18.56	[85]	Amount purified and sent to the grid

Gasification plant

Biomass input (TWh/year)	13.51	[85]	
Electricity share	1.75%	[85]	
Steam share	13%	[85]	Total efficiency from [85]
Steam efficiency	125%	[85]	Total efficiency from [85]
Coldgas efficiency	84.3%	[85]	Total efficiency from [85]
DH central share	22%	[85]	Heat used for water shift subtracted.

Electrolysers

Electrolyser capacity (MW-e)	685	[85]	
Electrolyser efficiency (Biomass hydrogenation)	89%	[85]	The electric efficiency of producing hydrogen is increased by the use of water shift in situations, where the electricity price is high. The water shift technology gets excess heat from gasification.
Electrolyser efficiency (Biogas hydrogenation)	82%	[85]	
Hydrogen storage [GWh]	1.92	[85]	Energinet utilises watershift technology to enable flexible operation of electrolysis in Sifre-Adapt. Watershift is not included in EnergyPLAN, and as such, this flexible operation is approximated by adding non-cost

			hydrogen storage to the EnergyPLAN versions. The size of the storage is set as being able to store 6 full load hours of operation.
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Biomass hydrogenation

Liquid fuel output (TWh/year)	9.73	[85]	
Liquid fuel efficiency	76.4%	[85]	
Hydrogen share	20.5%	[85]	
DH central share	4.4%	[85]	Heat used for central steam turbines subtracted.

Biogas hydrogenation

Gas fuel output (TWh/year)	0.41	[85]	
Gas fuel efficiency	80%	[85]	
Hydrogen share	36.5%	[85]	
DH decentral share	20%	[85]	

Electricity exchange

Transmission line capacity (MW)	12,735	[85]	
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Balancing

CEEP regulation strategy	2,3,4,5	[1]	IDA2050 strategy
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Distributions

The distributions do not influence the total annual energy, but allocates the total onto each hour of the year.

Input for distribution	Reference	Note
Electricity demand	[1]	IDA2050 distribution
Individual heat demand	[1]	IDA2050 distribution
Individual solar thermal	[1]	IDA2050 distribution
District heating demand	[1]	IDA2050 distribution
District heating solar thermal	[1]	IDA2050 distribution
Offshore Wind	[1]	IDA2050 distribution
Onshore Wind	[1]	IDA2050 distribution
Photo Voltaic	[1]	IDA2050 distribution

13 Appendix D – GCA2050

Input	Value	Reference	Note
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Electricity production

Fixed electricity demand (TWh/year)	39.12	[85]	The fixed electricity demand includes the “classic demand”, minus the 10% that are assumed flexible within 1 day, the electricity used for biofuelsynthesis and the electricity demand for process heat pumps.
Flexible electricity demand (1 day) (TWh/year)	3.91	[85]	10% of the classic electricity demand is flexible within 1 day.
Max-effect for flexible electricity demand (1 day) (MW)	705	[85]	Assumed to be equal to peak demand if distribution for “classic demand” was used.

Wind (onshore)

Capacity (MW)	6,164	[85]	Resulting capacity factor is 0.27
Annual production (TWh)	14.55	[85]	

Offshore Wind

Capacity (MW)	12,785	[85]	Including offshore and near shore wind power capacity. Capacity factor is 0.46
Annual production (TWh)	50.59	[85]	

Photo Voltaic

Capacity (MW)	11,450	[85]	Resulting capacity factor is 0.16
Annual production (TWh)	14.57	[85]	

Thermal power production

Large CHP units condensing power capacity (MW)	391	[85]	Excl. central steam turbines only operating on excess heat.
Large CHP units condensing power efficiency	40.4%	[85]	Excl. central steam turbines only operating on excess heat.
Capacity of large steam turbines operating on excess heat from gasification (MW)	100	[85]	A number of central steam turbines are operating on excess heat from the biomass hydrogenation. EnergyPLAN does not simulate the flows of excess heat, and as such, these units have been simulated in the “Dammed hydropower” category of EnergyPLAN, in order to adhere to the simulation logic of Energinets scenarios.
Annual electricity production by large steam turbines operating on excess heat from gasification (TWh)	0.51	[85]	A number of central steam turbines are operating on excess heat from the biomass hydrogenation. EnergyPLAN does not simulate the flows of excess heat, and as such,

			these units have been simulated in the “Dammed hydropower” category of EnergyPLAN, in order to adhere to the simulation logic of Energinets scenarios.
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District heating

Decentralised district heating

District heating production (TWh/year)	17.5	[85]	The amount of district heating produced by decentral plants.
Fuel boiler capacity (MW)	5,928		Assumed to be 120% of the simulated peak demand.
Fuel boiler efficiency	92%	[85]	Defined using the heat production divided by the amount of fuel used.
Small-scale CHP - Electric capacity (MW)	1,586		Excl. waste incineration (waste incineration capacity is assumed to be 160 MW based on yearly production and assumed 8000 full load hours). Total incl. Waste from [85].
Small-scale CHP - Electric efficiency	35.2%	[85]	The value represents the annual average efficiency.
Small-scale CHP - Thermal capacity (MW)	2,370	[85]	Based on average efficiencies and the electric capacity excl. waste incineration)
Small-scale CHP - Thermal efficiency	52.6%	[85]	The value represents the annual average efficiency.
Fixed boiler share	33%		Used to replicate the yearly productions from Energinets simulation. It represents the share of hours when boilers should not operate.
Grid loss	15%	[85]	
Thermal storage capacity (GWh)	15	[85]	The total DH storage capacity is 30 GWh, and it is here assumed that it is split 50/50 between central and decentral plants.
Solar thermal input (TWh/year)	0.51	[85]	
Industrial CHP heat produced (TWh/year)	1.18	[85]	Includes all district heating produced from “Process – Kraftvarme” and “Process Fjernvarme”, excl. heat coming from waste incineration the share of which is found based on assumed yearly efficiencies.
Industrial CHP electricity produced (TWh/year)	0.254	[85]	Includes all electricity produced from “Process – Kraftvarme”, excl. electricity coming from waste incineration the share of which is found based on assumed yearly efficiencies
Industrial CHP heat demand (TWh/year)	1.252	[85]	Includes district heating demand for industries.
Compression heat pump electric capacity (MW)	306	[85]	
Compression heat pump COP	3.5	[85]	Yearly average COP

Compression heat pump maximum share of load	0.5		Used to replicate the DH production from the Energinet simulations.
Electric boiler capacity (MW)	20	[85]	Divided between central and decentral based on total capacity and operation in each category.
Industrial excess heat (TWh/year)	0.525	[85]	The category “Overskudsvarme” from [85].

Central district heating

District heating production (TWh/year)	17.5	[85]	The amount of district heating produced by central plants.
Fuel boiler capacity (MW)	5,928		Assumed to be 120% of the simulated peak demand.
Fuel boiler efficiency	89.1%	[85]	Defined using the heat production divided by the amount of fuel used.
Large CHP - Electric capacity (MW)	391	[85]	
Large CHP - Electric efficiency	40.4%	[85]	
Large CHP - Thermal capacity (MW)	393	[85]	
Large CHP - Thermal efficiency	40.6%	[85]	
Fixed boiler share	1%		Used to replicate the yearly productions from Energinets simulation. It represents the share of hours when boilers should not operate.
Grid loss	15%	[85]	
Thermal storage capacity (GWh)	15	[85]	The total DH storage capacity is 30 GWh, and it is here assumed that it is split 50/50 between central and decentral plants.
Industrial CHP heat produced (TWh/year)	0.42	[85]	Heat output from the central steam turbines that are operating on excess heat from the gasification of biomass.
Industrial CHP electricity produced (TWh/year)	0	[85]	
Industrial CHP heat demand (TWh/year)	0	[85]	
Compression heat pump electric capacity (MW)	714	[85]	
Compression heat pump COP	3.5	[85]	Yearly average COP
Compression heat pump maximum share of load	0.81		Used to replicate the DH production from the Energinet simulations.
Electric boiler capacity (MW)	465	[85]	Divided between central and decentral based on total capacity and operation in each category.

Fuel Distribution and Consumption

Fuel Distribution for Heat and Power Production

These relations indicate for each of the plant type the fuel mix for used for each plant type (Coal / Oil / Gas / Biomass).

Small-scale CHP units	0 / 0 / 2 / 0.73	[85]	Based on fuel consumption from [85].
Large CHP units	0 / 0 / 1 / 0	[85]	Based on fuel consumption from [85].
Boilers in decentralised district heating	0 / 0.12 / 1.19 / 5.61	[85]	Based on fuel consumption from [85]. The oil demand is satisfied with electrofuels
Boilers in central district heating	0 / 0 / 0.15 / 0.02	[85]	Based on fuel consumption from [85].
Condensing operation of large CHP units	0 / 0 / 1 / 0	[85]	Based on fuel consumption from [85].
Condensing power plants	-	[85]	Based on fuel consumption from [85].

Additional fuel consumption (TWh/year)

Coal in industry	0	[85]	
Oil in industry	0	[85]	
Gas in industry	4.58	[85]	Includes gas consumption of “Process – Kraftvarme”, “Process – Fjernvarme” and “Process – Varme”
Biomass in industry	0	[85]	
Coal, various	0	[85]	
Oil, various	0	[85]	
Natural gas, various	0	[85]	

Transport

Conventional fuels (TWh/year)

JP (Jet fuel) - fossil	0	[85]	
Diesel - fossil	0	[85]	
Petrol - fossil	0	[85]	
Grid gas	8.16	[85]	
JP (Jet fuel) - biofuel	0	[85]	
Diesel - biofuel	0	[85]	
Petrol - biofuel	0	[85]	
JP (Jet fuel) - electrofuel	11.17	[85]	
Diesel - electrofuel	0	[85]	
Petrol - electrofuel	2.78	[85]	

Electricity (TWh/year)

Electricity - dump charge	5.94	[85]	
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Electricity – smart charge	11.51	[85]	All electric cars are assumed to be smart charge (not V2G), based on mail from Anders Bavnhøj
Max. share of cars during peak demand	20%	[1]	IDA2050 number
Capacity of grid to battery connection (MW)	29,213	[2][1][85]	Based on page 39 in “Systemperspektiv 2035 – Baggrundsrapport” and the IDA2050 scenario.
Share of parked cars grid connected	70%	[1]	IDA2050 number
Efficiency (grid to battery)	90%	[1]	IDA2050 number
Battery storage capacity (GWh)	25.3	[2][1][85]	Based on page 39 in “Systemperspektiv 2035 – Baggrundsrapport” and the IDA2050 scenario.

Waste conversion

Waste incineration in decentralised district heating

Waste input (TWh/year)	1.121	[85]	Incl. waste used for DH CHP, DH boilers, and process heat
Thermal efficiency	89.4%	[85]	
Electric efficiency	7.6%	[85]	

Waste incineration in central district heating

Waste input (TWh/year)	0.169	[85]	
Thermal efficiency	97.6%	[85]	
Electric efficiency	0	[85]	

Individual heating

Coal boilers

Fuel consumption (TWh/year)	0	[85]	
Efficiency	-		

Oil boilers

Fuel consumption (TWh/year)	0	[85]	
Efficiency	-		

Gas boilers

Fuel consumption (TWh/year)	0.2	[85]	
Efficiency	100%	[85]	Annual average value
Solar thermal input (TWh/year)	0	[85]	

Biomass boilers

Fuel consumption (TWh/year)	2.64	[85]	
Efficiency	89%	[85]	Annual average value
Solar thermal input (TWh/year)	0	[85]	

Heat pumps

Heat demand (TWh/year)	11.36	[85]	
COP	3.14	[85]	Annual average value
Solar thermal input (TWh/year)	1.367	[85]	

Electric heating

Heat demand (TWh/year)	0.26	[85]	Based on electricity demand for individual electric heating
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Biogas production

Biomass input (TWh/year)	26.24	[85]	
Biogas production (TWh/year)	18.78	[85]	
Biogas upgrade to grid efficiency	100%	[85]	Based on the produced amount minus the biogas to methanation, and the amount sent to the grid
Input to gas grid (TWh/year)	6.61	[85]	Amount purified and sent to the grid

Gasification plant

Biomass input (TWh/year)	13.14	[85]	
Electricity share	1.75%	[85]	
Steam share	13%	[85]	Total efficiency from [85]
Steam efficiency	125%	[85]	Total efficiency from [85]
Coldgas efficiency	84.6%	[85]	Total efficiency from [85]
DH central share	20.85%	[85]	Heat used for water shift subtracted.

Electrolysers

Electrolyser capacity (MW-e)	1938	[85]	
Electrolyser efficiency (Biomass hydrogenation)	89.1%	[85]	The electric efficiency of producing hydrogen is increased by the use of water shift in situations, where the electricity price is high. The water shift technology gets excess heat from gasification.
Electrolyser efficiency (Biogas hydrogenation)	86.8%	[85]	
Hydrogen storage [GWh]	7.66	[85]	Energinet utilises watershift technology to enable flexible operation of electrolysis in Sifre-Adapt. Watershift is not included in

			EnergyPLAN, and as such, this flexible operation is approximated by adding non-cost hydrogen storage to the EnergyPLAN versions. The size of the storage is set as being able to store 6 full load hours of operation.
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Biomass hydrogenation

Liquid fuel output (TWh/year)	10.72	[85]	
Liquid fuel efficiency	76.4%	[85]	
Hydrogen share	29.8%	[85]	
DH central share	9.55%	[85]	Heat used for central steam turbines subtracted.

Biogas hydrogenation

Gas fuel output (TWh/year)	15.33	[85]	
Gas fuel efficiency	80%	[85]	
Hydrogen share	36.5%	[85]	
DH decentral share	20%	[85]	

Electricity exchange

Transmission line capacity (MW)	12,735	[85]	
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Balancing

CEEP regulation strategy	2,3,4,5	[1]	IDA2050 strategy
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Distributions

The distributions do not influence the total annual energy, but allocates the total onto each hour of the year.

Input for distribution	Reference	Note
Electricity demand	[1]	IDA2050 distribution
Individual heat demand	[1]	IDA2050 distribution
Individual solar thermal	[1]	IDA2050 distribution
District heating demand	[1]	IDA2050 distribution
District heating solar thermal	[1]	IDA2050 distribution
Offshore Wind	[1]	IDA2050 distribution
Onshore Wind	[1]	IDA2050 distribution
Photo Voltaic	[1]	IDA2050 distribution

14 Appendix E – 2020 reference system

Input	Value	Reference	Note
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Electricity production

Electricity demand (TWh/year)	33.25	[61]	Electricity demand including grid losses, excluding demands for heating, cooling, and transport.
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Wind (onshore)

Capacity (MW)	4,232	[86]	
Annual production (TWh)	10.43	[61]	

Offshore Wind

Capacity (MW)	2051	[86]	
Annual production (TWh)	8.62	[61]	

Photo Voltaic

Capacity (MW)	952	[86]	
Annual production (TWh)	1.01	[61]	

River Hydro

Capacity (MW)	6.88	[87]	
Annual production (TWh)	0.02	[61]	

Thermal power production

Large CHP units condensing power capacity (MW)	3,112	[86]	
Large CHP units condensing power efficiency	36.3%	[61]	The value represents the expected annual average efficiency based on fuel consumption and production of these units as found in [61].
Reserve power plant capacity (MW)	557	[86]	
Condensing power plant efficiency	23.9%	[88]	The value represents the annual average efficiency.

District heating

Decentralised district heating

District heating production (TWh/year)	16.22	[61], [88]	The distribution of heat demand between decentralised and central district heating areas is from [88]. The total is from [61].
Fuel boiler capacity (MW)	6,354	[88]	Excl. units using biogas.

Fuel boiler efficiency	98.3%	[88]	
Small-scale CHP - Electric capacity (MW)	876	[86], [88]	Excl. waste incineration units. The waste incineration capacity based on [88].
Small-scale CHP - Electric efficiency	34%	[61]	The value represents the expected annual average efficiency based on fuel consumption and production of these units as found in [61].
Small-scale CHP - Thermal capacity (MW)	1,215		Based on found efficiencies.
Small-scale CHP - Thermal efficiency	47%	[61]	The value represents the expected annual average efficiency based on fuel consumption and production of these units as found in [61].
Fixed boiler share	20%	[61]	The value are found based on fuel consumption and production of these units as found in [61].
Grid loss	20%	[87]	
Thermal storage capacity (GWh)	33.2	[89]	
Solar thermal input (TWh/year)	1	[61]	
Industrial heat supply (TWh/year)	0.784	[61], [88]	The distribution between decentralised and central district heating areas is from [88]. The total is from [61]. Incl. units using biogas.
Industrial electricity supply (TWh/year)	0.363	[61], [88]	The distribution between decentralised and central district heating areas is from [88]. The total is from [61]. Incl. units using biogas.
Compression heat pump electric capacity (MW)	64	[86]	
Compression heat pump COP	3		Assumed.
Electric boiler capacity (MW)	489	[86]	

Central district heating

District heating production (TWh/year)	21.18	[61], [88]	The distribution of heat demand between decentralised and central district heating areas is from [88]. The total is from [61].
Fuel boiler capacity (MW)	6,109	[88]	
Fuel boiler efficiency	92.2%	[88]	
Large CHP - Electric capacity (MW)	1,760	[86], [88]	Found based on thermal capacity and found efficiencies.
Large CHP - Electric efficiency	28.3%	[61]	The value represents the expected annual average efficiency based on fuel consumption and production of these units as found in [61].
Large CHP - Thermal capacity (MW)	4,521	[86], [88]	Calculated using the thermal capacity from [88], with changes to central plants in operation listed in [86].

Large CHP - Thermal efficiency	72.7%	[61]	The value represents the expected annual average efficiency based on fuel consumption and production of these units as found in [61].
Fixed boiler share	0		
Grid loss	20%	[87]	
Thermal storage capacity (GWh)	15.7	[89]	
Industrial heat supply (TWh/year)	0.928	[61], [88]	The distribution between decentralised and central district heating areas is from [88]. The total is from [61]. Incl. units using biogas.
Industrial electricity supply (TWh/year)	0.103	[61], [88]	The distribution between decentralised and central district heating areas is from [88]. The total is from [61]. Incl. units using biogas.
Electric boiler capacity (MW)	271	[86]	

Cooling

Electricity for cooling (TWh/year)	1.67	[90]	
Electricity for cooling efficiency	4.55	[90]	

Fuel Distribution and Consumption

Fuel Distribution for Heat and Power Production

These relations indicate for each of the plant type the fuel mix for used for each plant type (Coal / Oil / Gas / Biomass). Oil is fixed through the year.

Small-scale CHP units	0 / 0.02 / 4.1 / 3.1	[61]	The gas usage is excl. biogas, as this fuel consumption is included in "Natural gas, various"
Large CHP units	3.15 / 0 / 1 / 18.9	[61]	The value are found based on fuel consumption and production of these units as found in [61].
Boilers in decentralised district heating	0 / 0 / 1.02 / 6.54	[61]	The value are found based on fuel consumption and production of these units as found in [61].
Boilers in central district heating	0 / 0 / 1.02 / 6.54	[61]	The value are found based on fuel consumption and production of these units as found in [61].
Condensing operation of large CHP units	10.06 / 0.4 / 0 / 0.5	[61]	The value are found based on fuel consumption and production of these units as found in [61].
Condensing power plants	0 / 1 / 0 / 0	[61]	

Additional fuel consumption (TWh/year)

Coal in industry	1.33	[61]	
Oil in industry	10.68	[61]	

Natural gas in industry	10.74	[61]	
Biomass in industry	2.98	[61]	
Coal, various	0	[61]	The fuel consumption in “Various” includes own consumption in the energy sector for producing and refining fuels. It also includes non-energy use of fuels.
Oil, various	6.65	[61]	
Natural gas, various	5.31	[61]	Is incl. biogas consumption at CHP and boiler units.
Biomass, various	0.47	[61]	

Transport

Conventional fuels (TWh/year)

JP (Jet fuel) - fossil	11.82	[61]	
Diesel - fossil	30.77	[61]	
Petrol - fossil	14.83	[61]	
Grid gas	0.06	[61]	
JP (Jet fuel) - biofuel	0	[61]	
Diesel - biofuel	1.98	[61]	
Petrol - biofuel	0.51	[61]	

Electricity (TWh/year)

Electricity dump charge	0.53	[61]	
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Waste conversion

Waste incineration in decentralised district heating

Waste input (TWh/year)	3.54	[61], [88]	The distribution of waste input between decentralised and central district heating areas is from [88]. The total is from [61].
Thermal efficiency	75.9%	[61]	
Electric efficiency	14.8%	[61]	Average electric efficiency for all waste incineration plants.

Waste incineration in central district heating

Waste input (TWh/year)	7.1	[61], [88]	The distribution of waste input between decentralised and central district heating areas is from [88]. The total is from [61].
Thermal efficiency	75.9%	[61]	
Electric efficiency	14.8%	[61]	Average electric efficiency for all waste incineration plants.

Individual heating

Coal boilers

Fuel consumption (TWh/year)	0	[61]	
Efficiency	70%		Assumed annual average value

Oil boilers

Fuel consumption (TWh/year)	2.13	[61]	
Efficiency	85%		Assumed annual average value
Solar thermal input (TWh/year)	0.013	[61]	The total solar thermal input from [61] is distributed on the fuel boiler types according to the fuel consumption.

Natural gas boilers

Fuel consumption (TWh/year)	7.00	[61]	
Efficiency	95%		Assumed annual average value
Solar thermal input (TWh/year)	0.043	[61]	The total solar thermal input from [61] is distributed on the fuel boiler types according to the fuel consumption.

Biomass boilers

Fuel consumption (TWh/year)	11.43	[61]	
Efficiency	80%		Assumed annual average value
Solar thermal input (TWh/year)	0.07	[61]	The total solar thermal input from [61] is distributed on the fuel boiler types according to the fuel consumption.

Heat pumps

Heat demand (TWh/year)	2	[86]	
COP	3		Assumed annual average value

Electric heating

Heat demand (TWh/year)	0.75	[87]	
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Biogas production

Biogas production (TWh/year)	5.42	[61]	
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Electricity exchange

Transmission line capacity (MW)	7,105	[86]	
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Balancing

Minimum CHP in group 3 (MW)	10	[91]	Based on minimum load in 2015
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Minimum PP (MW)	10	[91]	Based on minimum load in 2015
CEEP regulation strategy	2,3,4,5		

Distributions

The distributions do not influence the total annual energy, but allocates the total onto each hour of the year.

Input for distribution	Reference	Note
Electricity demand	[91]	Total electricity demand for East and West Denmark in 2015
Individual heat demand	[92]	Heat demand outside district heating areas in Denmark 2015. Generated using heating degree days with a reference temperature of 17°C and a temperature dependent of 75%. Hourly outdoor temperature from CFSR data [92].
Individual solar thermal	[93]	Solar thermal production in Denmark
District heating demand	[92]	Demand for district heating (incl. grid loss) in Denmark 2015. Generated using heating degree days with a reference temperature of 17°C and a temperature dependent of 75%. Hourly outdoor temperature from CFSR data [92].
District heating solar thermal	[93]	
Offshore Wind	[91]	Offshore wind power production in Denmark 2015
Onshore Wind	[91]	Onshore wind power production in Denmark 2015
Photo Voltaic	[91]	Photovoltaic power production in Denmark 2015

Fuel, variable OM and CO₂ price assumptions

The fuel prices and handling costs for the 2020 variant energy system are shown in Table 3. Fuel oil, Diesel fuel/Gas Oil, Biomass and Dry biomass costs are only given incl. handling cost for plants. Petrol/ JP1 cost is only given at airport and consumer level, hence the Fuel price is set for airport level.

[2015-EUR/GJ]	Coal	Natural gas	Fuel oil	Diesel fuel/ Gas Oil	Petrol/ JP1	Biomass	Dry biomass
Fuel price	2.71	4.75	7.49	15.92	11.88	6.6	8.9
Handling costs							
Power plants	0.17	0.34	0	-	-	0	0
Small plants and industry	0.17	1.25	0	-	-	0	-
Households	-	4.49	-	0	-	3.8	-
Road transport	-	-	-	0	4.24	-	-
Aviation	-	-	-	-	0	-	-

Table 3 – Fuel prices and handling costs in 2020 [61]

The CO₂ quota price is set at 6.45 EUR/t [61].

Appendix E – 2020 reference system

The variable OM cost is for the fuel boilers set at 0.15 EUR/MWh_{th}, for CHP units it is 2.7 EUR/MWh_e, for heat pumps it is 0.27 EUR/MWh_e, for electric heating it is 1.35 EUR/MWh_e and for condensing power plants it is 2.654 EUR/MWh_e. [1]

15 Appendix F – Overview of costs used

Shows the used investment costs, technical lifetime, fixed operation and maintenance costs, and variable operation and maintenance costs for the ST, GCA and IDA scenarios in 2035 and 2050. Comments in the section for investment costs also applies for Technical lifetime and Fixed operation and maintenance costs but are only stated in the section for Investment costs.

Investment costs

Heat and electricity

[M EUR/unit]		2035			2050		
Technology	Unit	ST	GCA	IDA	ST	GCA	IDA
Small CHP units	MW _e	1.73 ^a	1.73 ^a	1.2 ^j	1.09 ^b	1.32 ^c	1.1 ⁱ
Large CHP units	MW _e	1.44 ^d	1.44 ^d	1.44 ^d	0.8 ^e	0.8 ^e	0.8 ^e
Steam turbines	MW _e	-	0.481 ^f	-	0.481 ^f	0.481 ^f	-
Heat Storage CHP	GWh	3 ^h	3 ^h	3 ^h	3 ^h	3 ^h	3 ^h
Waste CHP	TWh/year	215.62 ^h	215.62 ^h	215.62 ^h	215.62 ^h	215.62 ^h	215.62 ^h
Heat Pump gr 2+3	MW _e	2.66 ⁱ	2.66 ⁱ	2.28 ⁱ	2.66 ⁱ	2.66 ⁱ	2.66 ⁱ
Boilers gr. 2+3	MW _{th}	0.345 ^g	0.345 ^g	0.69 ⁱ	0.315 ^g	0.315 ^g	0.67 ⁱ
Electr. boiler Gr 2+3	MW _e	0.06 ⁱ	0.06 ⁱ	0.06 ⁱ	0.06 ⁱ	0.06 ⁱ	0.06 ⁱ
Large power plants	MW _e	1.36 ^d	1.36 ^d	1.36 ^d	0.76 ^e	0.76 ^e	0.76 ^e
Interconnection	MW _e	1.2 ^h	1.2 ^h	1.2 ^h	1.2 ^h	1.2 ^h	1.2 ^h
Indust. CHP Electr.	TWh/year	63.5 ^h	63.5 ^h	63.5 ^h	60.6 ^h	60.6 ^h	60.6 ^h
Indust. CHP Heat	TWh/year	63.5 ^h	63.5 ^h	63.5 ^h	68.3 ^h	68.3 ^h	68.3 ^h

^a From [64]. 1/3 Medium steam turbine, woodchips (10-50 MWe) and 2/3 Spark ignition engine for gas CHP.

^b From [64]. 10% Medium steam turbine, woodchips (10-50 MWe) and 90% Spark ignition engine for gas CHP.

^c From [64]. 20% Medium steam turbine, woodchips (10-50 MWe) and 80% Spark ignition engine for gas CHP.

^d From [64]. 50% Steam turbine, fired by wood pellets, advanced steam process and 50% Gas turbine, combined cycle (steam extraction).

^e From [64]. Gas turbine, combined cycle (steam extraction)

^f From [18].

^g 50% natural gas boiler and 50% wood-chips boiler

^h From [1] with adjustments stated in [4]

ⁱ From [64].

^j From [64]. CCGT 10-100 MW.

Renewable energy

[M EUR/unit]		2035			2050		
Technology	Unit	ST	GCA	IDA	ST	GCA	IDA
Wind - onshore	MW _e	0.77 ^a	0.77 ^a	0.77 ^a	0.7 ^a	0.7 ^a	0.7 ^a
Wind - offshore	MW _e	1.93 ^a	1.93 ^a	1.93 ^a	1.78 ^a	1.78 ^a	1.78 ^a
Photo Voltaic	MW _e	0.55 ^b	0.56 ^c	0.63 ^h	0.73 ^d	0.73 ^e	0.49 ^h
Wave Power	MW _e	-	-	3.35 ^f	-	-	1.6 ^f
Geothermal heat	TWh/year	-	-	250 ^f	-	-	250 ^f
Solar Thermal	TWh/year	307 ^f	307 ^f	307 ^f	307 ^f	307 ^f	307 ^f
Heat storage solar	GWh	-	-	0.5	-	-	3 ^f
Indust. Excess heat	TWh/year	30 ^g	30 ^g	30 ^g	30 ^g	30 ^g	40 ^f

Appendix F – Overview of costs used

^a From [64].

^b From [64]. 15% is household systems, 38% is medium sized commercial, 47% are large commercial systems on fields.

^c From [64]. 12% is household systems, 50% is medium sized commercial, 22% are large commercial systems on fields.

^d From [64]. 5% is household systems, 78% is medium sized commercial, 17% are large commercial systems on fields.

^e From [64]. 5% is household systems, 81% is medium sized commercial, 14% are large commercial systems on fields.

^f From [1] with adjustments stated in [4]

^g From [94].

^h From [64]. Medium sized commercial.

Liquid and gas fuels

[M EUR/unit]		2035			2050		
Technology	Unit	ST	GCA	IDA	ST	GCA	IDA
Biogas Plant	TWh/year	-	176.19 ^a	176.19 ^a	159.03 ^a	159.03 ^a	159.03 ^a
Gasification Plant	MW	-	1.638 ^b	1.56 ^a	1.397 ^b	1.397 ^b	1.33 ^a
Biogas Upgrade	MW	-	0.27 ^a	0.27 ^a	0.25 ^a	0.25 ^a	0.25 ^a
Gasification Upgrade	MW	-	0.8 ^a	-	0.68 ^a	0.68 ^a	0.68 ^a
Carbon recycling	MtCO ₂ /y	-	-	60 ^c	-	-	60 ^c
LiquidFuel synth (CO ₂)	MW	-	-	0.5 ^c	-	-	0.3 ^c
LiquidFuel synth (biomass)	MW	-	0.5 ^c	0.5 ^c	0.3 ^c	0.3 ^c	0.3 ^c
Methanation (biogas)	MW	-	0.3 ^c	0.3 ^c	0.2 ^c	0.2 ^c	0.2 ^c
JP Synthesis	MW	-	0.37 ^d	0.37 ^d	0.37 ^d	0.37 ^d	0.37 ^d
SOEC Electrolyser	MW-e	-	0.6 ^a	0.6 ^a	0.4 ^a	0.4 ^a	0.4 ^a
Hydrogen Storage	GWh	-	-	7.6 ^e	-	-	7.6 ^e

^a From [67].

^b From [67]. Incl. 5% cost for watershift.

^c From [95].

^d From [96].

^e From [94].

Heat infrastructure

[M EUR/unit]		2035			2050		
Technology	Unit	ST	GCA	IDA	ST	GCA	IDA
Indv. Boilers	1000-units	4.88 ^a	5.35 ^a	6.5 ^a	5.90 ^a	5.90 ^a	5.90 ^a
Indv. Heat Pump	1000-units	8 ^b	8 ^b	8 ^b	7 ^b	7 ^b	7 ^b
Indv. Electric heat	1000-units	2.8 ^c	2.8 ^c	2.8 ^c	2.5 ^c	2.5 ^c	-
Indv. Solar thermal	TWh/year	-	1533 ^d	1533 ^d	1233 ^d	1233 ^d	1233 ^d

^a From [62]. Split between biomass automatic stoking and gas boilers according to share of heat production.

^b From [62]. 50/50 split between air-to-water and brine-to-water in new one family houses.

^c From [62].

^d From [1].

Additional costs

[M EUR]	2035			2050		
Technology	ST	GCA	IDA	ST	GCA	IDA
Electric grid	1317 ^a	1513 ^a	1507 ^a	1958 ^a	2210 ^a	2475 ^a
District heating grid	16703 ^a	16703 ^a	16703 ^a	16703 ^a	16703 ^a	16703 ^a
Interconnections	1092 ^a	1333 ^a	743 ^a	1092 ^a	1333 ^a	743 ^a

Appendix F – Overview of costs used

Compression cooling (Refrigeration)	559 ^a	559 ^a	559 ^a	559 ^a	559 ^a	559 ^a
Compression cooling (room temp)	5031 ^a	5031 ^a	3913 ^a	5031 ^a	5031 ^a	2795 ^a
District cooling (only for room temp)	-	-	207 ^a	-	-	413 ^a
Combined district cooling & heating (only for room temp)	-	-	620 ^a	-	-	1239 ^a
Electricity savings in households	545 ^a	545 ^a	545 ^a	1364 ^a	1364 ^a	1364 ^a
Electricity savings in industry	1483 ^a	1483 ^a	1997 ^a	2595 ^a	2595 ^a	3491 ^a
Fuel savings in industry	6468 ^a	6468 ^a	6468 ^a	10011 ^a	10011 ^a	10011 ^a
Flexible electricity demand in households	222 ^a	222 ^a	222 ^a	222 ^a	222 ^a	222 ^a
Flexible electricity demand in industry	244 ^a	244 ^a	244 ^a	244 ^a	244 ^a	244 ^a
District heating grid expansion	5448 ^a	5448 ^a	5448 ^a	5448 ^a	5448 ^a	5448 ^a
Heat savings existing buildings	19559 ^a	19559 ^a	19559 ^a	32592 ^a	32592 ^a	32592 ^a
Vehicles	- ^b	- ^b	45246 ^a	- ^b	- ^b	40874 ^a
Charging stations	- ^b	- ^b	1307 ^a	- ^b	- ^b	2149 ^a
Marginal transport infrastructure	- ^b	- ^b	41064 ^a	- ^b	- ^b	37396 ^a
Transport other	- ^b	- ^b	360 ^a	- ^b	- ^b	337 ^a

^a Based on method from [1].

^b Totals unknown therefore left empty.

Technical lifetime

Heat and electricity

[Years]	2035			2050		
Technology	ST	GCA	IDA	ST	GCA	IDA
Small CHP units	25	25	25	25	25	25
Large CHP units	25	25	25	25	25	25
Steam turbines	-	25	-	25	25	-
Heat Storage CHP	20	20	20	20	20	20
Waste CHP	20	20	20	20	20	20
Heat Pump gr 2+3	25	25	25	25	25	25
Boilers gr. 2+3	25	25	25	25	25	25
Electr. boiler Gr 2+3	20	20	20	20	20	20
Large power plants	25	25	25	25	25	25
Interconnection	40	40	40	40	40	40
Indust. CHP Electr.	31	31	31	31	31	31
Indust. CHP Heat	31	31	31	25	25	25

Renewable energy

[Years]	2035	2050
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Appendix F – Overview of costs used

Technology	ST	GCA	IDA	ST	GCA	IDA
Wind - onshore	30	30	30	30	30	30
Wind - offshore	30	30	30	30	30	30
Photo Voltaic	40	40	40	40	40	40
Wave Power	-	-	25	-	-	30
Geothermal heat	-	-	25	-	-	25
Solar Thermal	30	30	30	30	30	30
Heat storage solar	-	-	20	-	-	20
Indust. Excess heat	30	30	30	30	30	30

Liquid and gas fuels

<i>[Years]</i>	2035			2050		
Technology	ST	GCA	IDA	ST	GCA	IDA
Biogas Plant	-	20	20	20	20	20
Gasification Plant	-	20	20	20	20	20
Biogas Upgrade	-	15	15	15	15	15
Gasification Upgrade	-	20	-	20	20	20
Carbon recycling	-	-	20	-	-	20
LiquidFuel synth (CO ₂)	-	-	25	-	-	25
LiquidFuel synth (biomass)	-	25	25	25	25	25
Methanation (biogas)	-	25	25	25	25	25
JP Synthesis	-	25	25	25	25	25
Electrolyser	-	15	15	20	20	20
Hydrogen Storage	-	-	25	-	-	25

Heat infrastructure

<i>[Years]</i>	2035			2050		
Technology	ST	GCA	IDA	ST	GCA	IDA
Indv. Boilers	20	20	20	20	20	20
Indv. Heat Pump	19	19	19	19	19	19
Indv. Electric heat	30	30	-	30	30	-
Indv. Solar thermal	-	30	30	30	30	30

Additional costs

<i>[Years]</i>	2035			2050		
Technology	ST	GCA	IDA	ST	GCA	IDA
Electric grid	45	45	45	45	45	45
District heating grid	40	40	40	40	40	40
Interconnections	45	45	45	45	45	45
Compression cooling (Refrigeration)	15	15	15	15	15	15
Compression cooling (room temp)	15	15	15	15	15	15
District cooling (only for room temp)	-	-	25	-	-	25

Appendix F – Overview of costs used

Combined district cooling & heating (only for room temp)	-	-	25	-	-	25
Electricity savings in households	10	10	10	10	10	10
Electricity savings in industry	15	15	15	15	15	15
Fuel savings in industry	20	20	20	20	20	20
Flexible electricity demand in households	20	20	20	20	20	20
Flexible electricity demand in industry	20	20	20	20	20	20
District heating grid expansion	40	40	40	40	40	40
Heat savings existing buildings	50	50	50	50	50	50
Vehicles	-	-	13	-	-	13
Charging stations	-	-	10	-	-	10
Marginal transport infrastructure	-	-	30	-	-	30
Transport other	-	-	1	-	-	1

Fixed operation and maintenance costs

Heat and electricity

<i>[% of investment]</i>	2035			2050		
Technology	ST	GCA	IDA	ST	GCA	IDA
Small CHP units	3.07	3.07	2.31	1.90	2.48	2.36
Large CHP units	2.78	2.78	2.78	3.25	3.25	3.25
Steam turbines	-	3.00	-	3.00	3.00	-
Heat Storage CHP	0.7	0.7	0.7	0.7	0.7	0.7
Waste CHP	7.37	7.37	7.37	7.37	7.37	7.37
Heat Pump gr 2+3	0.26	0.26	0.26	0.26	0.26	0.26
Boilers gr. 2+3	4.75	4.75	4.5	4.87	4.87	4.3
Electr. boiler Gr 2+3	1.7	1.7	1.7	1.53	1.53	1.53
Large power plants	2.78	2.78	2.78	3.25	3.25	3.25
Interconnection	1	1	1	1	1	1
Indust. CHP Electr.	2.14	2.14	2.14	2.15	2.15	2.15
Indust. CHP Heat	2.14	2.14	2.14	7.3	7.3	7.3

Renewable energy

<i>[% of investment]</i>	2035			2050		
Technology	ST	GCA	IDA	ST	GCA	IDA
Wind - onshore	1.64	1.64	1.64	1.62	1.62	1.62
Wind - offshore	1.87	1.87	1.87	1.82	1.82	1.82
Photo Voltaic	1.35	1.37	1.37	1.55	1.56	1.59
Wave Power	-	-	-	-	-	4.9
Solar Thermal	0.15	0.15	0.15	0.15	0.15	0.15
Heat storage solar	-	-	0.7	-	-	0.7
Indust. Excess heat	1	1	1	1	1	1

Liquid and gas fuels

<i>[% of investment]</i>	2035			2050		
Technology	ST	GCA	IDA	ST	GCA	IDA
Biogas Plant	-	14	13	13	14	14
Gasification Plant	-	2.4	2.3	2.3	2.4	2.4
Biogas Upgrade	-	2.5	2.5	2.5	2.5	2.5
Gasification Upgrade	-	1.7	-	1.4	1.7	1.7
Carbon recycling	-	-	-	-	-	4
LiquidFuel synth (CO ₂)	-	-	-	-	-	4
LiquidFuel synth (biomass)	-	4	4	4	4	4
Methanation (biogas)	-	4	4	4	4	4
JP Synthesis	-	4	4	4	4	4
Electrolyser	-	3	3	3	3	3
Hydrogen Storage	-	-	2.5	-	-	2.5

Heat infrastructure

<i>[% of investment]</i>	2035			2050		
Technology	ST	GCA	IDA	ST	GCA	IDA
Indv. Boilers	6.61	6.76	7.14	7.12	7.12	7.12
Indv. Heat Pump	3.06	3.06	3.06	2.75	2.75	2.75
Indv. Electric heat	0.82	0.82	-	0.84	0.84	-
Indv. Solar thermal	-	1.35	1.35	1.68	1.68	1.68

Additional costs

<i>[% of investment]</i>	2035			2050		
Technology	ST	GCA	IDA	ST	GCA	IDA
Electric grid	1	1	1	1	1	1
District heating grid	1.25	1.25	1.25	1.25	1.25	1.25
Interconnections	1	1	1	1	1	1
Compression cooling (Refrigeration)	0	0	0	0	0	0
Compression cooling (room temp)	4	4	4	4	4	4
District cooling (only for room temp)	-	-	2	-	-	2
Combined district cooling & heating (only for room temp)	-	-	2	-	-	2
Electricity savings in households	0	0	0	0	0	0
Electricity savings in industry	0	0	0	0	0	0
Fuel savings in industry	0	0	0	0	0	0
Flexible electricity demand in households	1	1	1	1	1	1
Flexible electricity demand in industry	1	1	1	1	1	1
District heating grid expansion	1.25	1.25	1.25	1.25	1.25	1.25
Heat savings existing buildings	0	0	0	0	0	0
Vehicles	-	-	6.85	-	-	7.06
Charging stations	-	-	0	-	-	0

Appendix F – Overview of costs used

Marginal transport infrastructure	-	-	0	-	-	0
Transport other	-	-	0	-	-	0

Variable operation and maintenance costs

<i>[M EUR/unit]</i>		2035			2050		
Technology	Unit	ST	GCA	IDA	ST	GCA	IDA
Small and large CHP units	MWh _e	3.69 ^a	3.22 ^a	3.36 ^a	4.7 ^a	4.69 ^a	4 ^a
Heat Pump gr 2+3	MWh _e	0.43 ^a	0.43 ^a	0.43 ^a	0.43 ^a	0.43 ^a	0.43 ^a
Boilers gr. 2 and 3	MWh _{th}	1.05 ^a	1.05 ^a	0.5 ^a	1.05 ^a	1.05 ^a	0.5 ^a
Electr. boiler Gr 2+3	MWh _e	0.5 ^a	0.5 ^a	0.5 ^a	0.4 ^a	0.4 ^a	0.5 ^a
Large power plants	MWh _e	2.65 ^a	2.65 ^a	2.92 ^a	4 ^a	4 ^a	4 ^a

^a From [64].

16 Appendix G – Adjustments to the IDA scenario

- Redefined energy balances in the CO₂ and biomass hydrogenation due to the new split between liquid and gaseous fuels (These were mixed in one output in previous versions of EnergyPLAN, though with EnergyPLAN v15 these are now separated).
- Updated the biogas methanation based on new EnergyPLAN improvements (methanation separated from biogas purification) and Danish biogas composition (65% CH₄ and 35% CO₂).
- The new energy balances on fuel production result in using less hydrogen than in the old model version, so the hydrogen capacity and hydrogen storage are reduced by 5%. This also includes adjusting the electrolyser efficiency upwards from 73% to 74%.
- Due to the changes in CEEP utilization in EnergyPLAN v15, the Max Capacity for CO₂ capture is now adjusted to match the flexible production in the original IDA. This increase refers to a Max Cap of 1050 tCO₂/hour, while the average is 445 tCO₂/hour.
- Electricity consumption from CO₂ recycling is now accounted in the total electricity consumption.
- In the new setup, power plants operate more hours, so additional syngas from biomass gasification is required for electricity production and a higher biomass consumption. This results in 0.4 TWh of extra biomass consumed which also reflects in the primary energy supply, now at 0.43 TWh higher compared to the original IDA.